OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **February 5, 2018**

TO: Phillip Fielder, P.E., Permits and Engineering Group Manager

THROUGH: Phil Martin, P.E., Manager, Existing Source Permits Section

THROUGH: Amalia Talty, P.E., Existing Source Permits Section

FROM: David Schutz, P.E., New Source Permit Section

SUBJECT: Evaluation of Permit Application No. **2010-599-C (M-8)(PSD)**
HollyFrontier Tulsa Refining LLC (Formerly Holly Refining & Marketing)
Tulsa Refinery West
Expansion of Tulsa Refinery
1700 South Union
Tulsa, Tulsa County, OK (36.13765° N, 96.01154° W)
FAC ID 1477

SECTION I. INTRODUCTION

HollyFrontier Tulsa Refining (HFRT) has requested a modification to their PSD construction permit, Permit No. 2010-599-C (M-7)(PSD) issued January 8, 2016. The overall project will now involve the following units:

- The MEK Unit itself has fugitive VOC leakage components in EUG-7. The component counts are being updated. The "MEK Unit" uses methyl ethyl ketone to extract wax from paraffins from the Lube Extraction Unit (LEU). Since the unit was considered "modified" previously, making it subject to NSPS Subpart GGGa, the counts update is not a "modification" in the context of NSPS but does change emission rates.

- The external shell of the Crude Distillation Unit (CDU) will be repaired. The permit application is treating this repair project as a "life extension" project subject to PSD permitting analyses. The primary effect of this change is moving the fugitive components from EUG-7 to EUG-8; all other changes in throughputs and emissions are part of the overall project to expand the refineries.

- The HFTR-West Refinery Asphalt Truck Loading Dock has four bays. Since about 1992, only one bay has been needed; the other three have been out of service. One of the out of service bays has been reactivated, and an additional loading bay was installed in August 2016. The re-activated and new bays allow East Refinery VTB and PDA to be sent to the Coker. The resulting emissions have been added to EUG 32.

The two refineries owned by HFTR were acquired at separate times, therefore, are permitted separately. The loading terminal is owned operated by HEP, resulting in another separate permit for it. However, the two refineries and loading terminal are interconnected and collocated, requiring that they be treated as a single facility when conducting a PSD analysis. For the purpose of the PSD analysis only, HFTR and HEP together are at times referred to as "Holly."

Part of the change in the net emissions change analysis involves a heater at the East Refinery. A heater designated 1H-101 in EUG-27 serving the Distillate Hydrotreating Unit (DHTU) was previously stated as having a capacity of 55 MMBTUH, but the firing rate is being corrected to 80 MMBTUH. Although the heater is not being physically modified, the different capacity will impact previous PSD permit analyses including emissions changes and ambient impacts. Additionally, the emissions from the sulfur recover unit (SRU-2) have been updated to reflect the results of the stack test plus a safety factor and modeling changes were incorporated to reflect the reduction in FCCU heater stack height.

HFTR and HEP proposed a construction project to expand the refineries and loading terminals. The project commenced in the 2014-2015 time frame. There will be new process units added and modification of existing process units such that the total capacities of the refineries will be increased to 170,000 BPD from the current capacity of 160,000 BPD. There will be "associated" emissions increases from most units in the refinery, excepting those emissions units which are independent of unit process rates such as emergency engines, fugitive VOC leakage from valves, flanges, etc.

The six proposed changes to the two PSD permits (three at the West Refinery and three at the East Refinery) are evaluated in the following updated PSD analysis.

The net emissions change analysis applies to all three, and all PSD analyses other than BACT will encompass all three facilities. The BACT analysis in this permit will be limited to the types of units being added to the West Refinery. Reductions required for netting have been added to the East Refinery construction permit.

Over the previous 5 years, there have been multiple construction projects which were subject either to PSD review or to requirements to keep records of actual emissions to show that the difference between Baseline Actual Emissions and Actual Emissions did not exceed PSD levels of significance. Those permits will be superseded by this construction permit, incorporating those preceding changes as part of the "net emissions changes" in the PSD netting analysis.

The proposed project is subject to Prevention of Significant Deterioration (PSD) review for added emissions of greenhouse gases (GHG), carbon monoxide (CO), nitrogen oxides (NOx), and particulate matter (PM_{10} / $PM_{2.5}$). Full PSD review consists of:

- **A.** determination of best available control technology (BACT)
- **B.** evaluation of existing air quality and determination of monitoring requirements
- **C.** evaluation of PSD increment consumption
- **D.** analysis of compliance with National Ambient Air Quality Standards (NAAQS)
- **E.** ambient air monitoring
- **F.** evaluation of source-related impacts on growth, soils, vegetation, visibility

G. evaluation of Class I area impacts.

The refinery will also accept NSPS Subpart Ja limits on SO_2 emissions on all fuel gas combustion devices to net out from PSD for SO_2. New tanks will be added to the West Refinery, but the final designs are not yet ready. As an interim measure, a limit of 26.7 TPY VOC from the new tanks will be established.

SECTION II. FACILITY DESCRIPTION

HFTR's crude is received by pipeline and tanker truck. The crude is a mixture of purchased crude oils from various sources, which, when blended, has the required properties to make the petroleum products. Refinery fuel gases, propane, butane, isobutane, normal butane, gasolines, kerosene, No. 2 fuel oil, paraffin wax, petroleum coke, and Lube Extracted Feedstock (LEF) are some of the current byproducts from making the lube oils. LEF is a mixture of unfinished streams that may also be transferred to third party purchasers.

The specific types of refining process and support facilities in current use in the HFTR West Refinery are discussed in the following paragraphs. All of the process units and associated support equipment at HFTR operate as a whole (one primary operating scenario). Individual units or pieces of equipment undergo periodic scheduled shutdown for maintenance, but no one unit or piece of equipment has any permit restrictions on potential operating hours. Therefore, total potential operating hours per year for all equipment is 24 hours per day, seven days per week, for every day of the year.

A. Crude Distillation Unit (CDU)

The Crude Distillation Unit is the first process and is used to separate crude oil or mixtures of crude and other purchased crude fractions into specific boiling-range streams suitable either for further processing in downstream units or in some cases, for direct sale after mild treating or blending. The primary equipment associated with this operation is a main atmospheric pressure fractionator, a light ends fractionator called the "stabilizer tower," and two in-series vacuum distillation units. The atmospheric tower recovers streams that boil at approximately atmospheric pressure. The stabilizer tower feeds overhead gas to the crude tower and, at high pressure, effects a first separation of gases (which go to the refinery fuel gas system) from crude gasoline. The vacuum towers recover high boiling point fractions that can be recovered only by lowering the pressure and operating at elevated temperatures. The energy for the distillation steps is provided by a main crude heater and two vacuum charge heaters, all gas fired. Other equipment important to crude and vacuum distillation is an extensive heat exchange system, a crude desalter system, and a vacuum producing system.

B. Light Ends Recovery Unit (LERU)

The light gases from the Crude Unit Stabilizer are processed in a deethanizer tower and a depropanizer tower in the LERU. The deethanizer is a high-pressure fractionator that separates ethane and lighter fuel gases from propane and heavier hydrocarbons. The depropanizer tower is a pressurized tower that fractionates deethanizer bottoms into a liquid propane stream and a liquid mixed butane/pentane stream. The propane is treated with potassium hydroxide for sulfur removal, stored in tankage, and sold as commercial liquefied petroleum gas (LPG). The mixed butane/pentane from the depropanizer is stored in pressurized storage prior to further fractionation. Energy for the LERU process is provided by steam passing through reboilers (heat exchangers).

C. Isomerization Unit Towers

The isomerization reactors are shut down, but an associated fractionation system for separating manufactured and natural isobutane from normal butane remains in operation. Feed is the LERU butane/pentane stream from storage. The butane/pentane is brought from storage and treated with potassium hydroxide for sulfur removal and fed to the deisobutanizer which first creates a propane/isobutane feed for a depropanizer that separates propane as an overhead stream from isobutane as a bottoms stream. The propane is stored and sold as LPG. The isobutane is stored in a pressurized tank and sold as isobutane. Deisobutanizer bottoms are fed to a debutanizer for recovery of normal-butane as an overhead product (to sales or to gasoline blending), and pentane bottoms which goes to gasoline blending.

D. Depentanizer and Naphtha Splitter

The Crude Unit Stabilizer tower bottoms charge the fraction tower called the de-pentanizer. This de-pentanizer makes an overhead liquid stream called light straight run gasoline which goes to gasoline blending. Bottoms, called naphtha, are split via level control with part going to the Unifiner and part to Lube Extracted Feedstock (LEF) and shipped to the Sunoco Toledo Refinery or other third party purchasers. Splitter bottoms join crude naphtha as feed to the downstream Unifiner Unit. Energy for the de-pentanizer is supplied by a gas fired heater.

E. Unifiner

The Unifiner Unit has the purpose of treating naphtha from the Crude Unit and the depentanizer bottoms in preparation for conversion to high-octane gasoline in the downstream No. 2 Platformer Unit. The Unifiner includes a hydrogen-treating reactor that removes sulfur and other contaminants that would be detrimental to the downstream Platformer. Other major equipment includes a hydrogen compressor, gas/liquid reactor effluent separator vessels, a stripper column to remove gases from the reactor product, and heat exchange systems. Two gas-fired heaters supply energy for the reactors and stripper column.

F. No. 2 Platformer

Unifiner effluent charges the Platformer, which catalytically converts the low-octane paraffin hydrocarbons to high-octane aromatics for gasoline blending. Naphtha feed is preheated by heat exchange, charged to a series of four endothermic catalytic reactors (four gas-fired heaters supply the heat of reaction), flashed to separate gas from product, and distilled through a debutanizer tower. The debutanizer is energized by a gas-fired reboiler heater. Hydrogen and other light gases are by-products that are primarily sent to refinery fuel gas, although a hydrogen-rich stream is used to provide hydrogen to the Unifiner reactors and the lube hydrotreater.

G. Lube Oil Extraction and Hydrogenation

This unit is charged with vacuum gas oil fractions and paraffinic deasphalted oil which flows into two parallel counter-current solvent extraction towers that utilize furfural as a solvent. As a result, two streams are produced, a waxy paraffinic stream suitable for lube oil manufacture and an aromatic stream that is either blended with lube oil extracted feedstock for pipeline shipment to the Sunoco Toledo Refinery or sold as extract product. The waxy paraffinic stream is fed to a hydrogenation unit to improve its stability and remove impurities before going to a downstream dewaxing operation. The hydrotreater is a fixed bed catalytic unit that uses hydrogen from the No. 2 Platformer. The unit employs towers, vessels, heat exchangers, pumps, etc., to remove and recycle the furfural solvent from the product streams. Three gas-fired heaters provide energy for the process.

H. MEK Dewaxing Unit

This unit removes wax from the hydrotreated paraffins from the Lube Extraction Unit. The process employs two solvents in mixture, toluene and methyl-ethyl-ketone. Fabric filters on rotating drums are used to physically separate wax from oil. A propane refrigeration system provides cooling to effect wax precipitation out of oil/wax solutions. Paraffin streams are fed in blocked out batches (the boiling range of the various batches having been set when recovered as separate streams at the Crude Unit vacuum towers). The dewaxed oil batches are stored and used for finished lube oil blending. The deoiled wax batches are stored and sold as various melt point products. The unit equipment includes oil/solvent contactors, rotating drum fabric filters, towers and vessels for solvent recovery and recycle, a propane refrigeration compressor system, a flue gas compressor system associated with the fabric filters, pumps, heat exchangers, etc. Two gas fired process heaters are employed, one for oil/solvent separation, and one for soft wax/solvent separation.

I. Coker Unit

HFTR's Coker Unit produces solid coke particles in a batch process. The Coker Unit equipment list includes two gas fired process heaters, two coke drums, a main fractionator, and other towers, vessels, pumps, heat exchangers, etc. The Coker Unit alternates the process between two vessels called drums. One drum is being charged for processing while the other is being emptied or "de-headed." The process begins by charging one of the coke drums with the asphaltic stream from the Deasphalting Unit. The process thermally separates the heavy molecules into carbon (coke) and light hydrocarbons. The charge is heated to 900°F using two gas-fired process heaters and then is allowed to have residence time while the coke and the light hydrocarbons separate. The light hydrocarbons flow to the product fractionation system (a part of the Coker Unit) for separation into gas for refinery fuel, and liquids which are pipe to the Sunoco Toledo Refinery or to third party purchasers, and gasoline for recovery back through the Crude Unit stabilizer. After a drum is de-headed it is cleaned out with steam for the next batch. Coke is stored in piles on-site, for bulk shipment by rail or trucks. Air emissions from handling the finished coke are insignificant.

J. ROSE Unit

The existing Propane Deasphalting Unit (PDA) will be modified and expanded to be a ROSE Unit. Residuum Oil Supercritical Extraction (ROSE) is a process where a light, condensable hydrocarbon such as liquid propane or isobutene is used to treat the "residuum oil," or bottoms from the vacuum distillation unit. Residuum contains a mixture of heavy oils from which FCCU feed ("gas oil") can be separated from asphaltenes. The process mixes the light hydrocarbon with the residuum, extracting the gas oil from the asphaltenes. Asphaltenes are processed off-site to produce road and roofing asphalt, and the light hydrocarbon is evaporated out from the gas oil. The light hydrocarbons are condensed back to liquids then recycled to the process. The unit capacity, as a PDA Unit, is 12,000 BPD; it will be modified to 15,000 BPD capacity.

K. Lube/Wax Blending and Sales/Service Operations

This refinery produces finished paraffinic lubricating oils. These waxes are also an important by-product of lube oil manufacturing process. To provide the specialty products required by HFTR's diverse customers, there is a product blending and shipping operation at the site. The blending primarily occurs in cone roof tank areas. Packaging and package storage is conducted in the Lube Service Center building. Shipment is by bulk in tank trucks and tank railcars.

L. Steam Generation

There are four gas-fired boilers that produce steam for general refinery use. The individual boiler units are numbered Nos. 7, 8, 9 and 10.

M. Wastewater Treatment

Facility wastewaters are conveyed in combined storm/process sewers, through oil/water separators and to a treatment area that employs storm surge capacity, clarification, dissolved air floatation, equalization, and aerobic waste digestion. Treated water is discharged to the Arkansas River. Recovered sludges are deoiled at a centrifuge facility and the oil is fed to the Coker Unit or Crude Unit.

N. Cooling Towers

The refinery employs 8 non-contact cooling towers. These are systems that circulate captive waters that provide a heat sink for various process units or equipment. Water is circulated through heat exchangers to indirectly cool hydrocarbon or other streams. Hot water from these exchangers is collected by pipelines and sprayed over packed towers in counter current flow to atmospheric air. The evaporation of a portion of the hot (typically 100 to 120°F) circulated water provides cooling to about 85°F (summer) for recirculation back to the heat exchangers. The white plumes observed from these towers are the evaporated water that sometimes re-condenses cloud-like at certain atmospheric conditions. The cooling towers have not used chrome-based systems since before 1994 and are not subject to MACT Subpart Q.

O. Flare Stacks

The refinery employs three vertical, piloted flare stacks for the emergency containment and combustion of certain hydrocarbon releases. Various HFTR process equipment is fitted with pressure relief valves to protect against overpressure conditions. These pressure relief valve outlets discharge into a gas collection flare piping system. Each flare stack uses a continuous pilot light that assures ignition of any gaseous discharges. Each flare also uses a steam system that supplies steam for mixing with the gas being flared (as needed) to reduce/prevent the combustion products from smoking.

P. Logistics and Storage

The HFTR logistics system involves feed and product receipt and shipment systems, as well as extensive internal movements. Crude feed material is primarily received by pipeline into large tanks. Product shipments are also made by pipeline, tank truck, rail tank car, and package truck trailer. This refinery does not have a marine terminal. There is an extensive storage tank system that handles crude feeds, finished products, and process intermediates. Types of material are generally in common geographical areas, but there are many exceptions due to the long history of the site.

Q. Sulfur and Other Impurity Treatments

This refinery processes feeds that are low in sulfur content, and does not employ a fluid catalytic cracker or a large hydrotreater or hydrocracker. The refinery fuel gas loop shall meet the H_2S limit set forth in 40 C.F.R. §60.104(a); and (b) at least 95% of the sulfur removed shall be recovered. Refined product sulfur impurities are addressed within specific process units by caustic or chemical treatment steps.

SECTION III. PROPOSED PROJECT DESCRIPTIONS

The proposed projects for each facility are listed following. The new and modified units are categorized as combustion units (heaters); process units with fugitive VOC leakage from valves, flanges, etc.; the Fluid Catalytic Cracking Unit (FCCU); the Continuous Catalyst Regenerator serving the Platformer Unit; and storage tanks.

West Refinery

- Propane Deasphalter (PDA) Unit revamp and modification to become a Residuum Oil Supercritical Extraction (ROSE) Unit, with a new 76 MMBTUH HHV heater;
- A new 10 MMSCFD Hydrogen (H_2) Plant will be constructed, with a reformer heater sized at 125 MMBTUH. The heater will be fueled with natural gas or refinery fuel gas, which may include Pressure Swing Absorption (PSA) off-gas.
- New tanks will be added to the West Refinery, but the final designs are not yet ready. As an interim measure, a limit of 26.69 TPY VOC from the new tanks will be established.

HEP (Loading Terminal and Storage)

• A new 90,000 BPCD Inline Gasoline Blender.
• A new Propane Loading Unit will replace the existing Propane Loading Unit.
• Construction of new tanks with VOC emissions up to 22.1 TPY will be authorized, but specifications for the new tanks are not yet known.

East Refinery

• A new 10,000 BPCD Liquid Petroleum Gas (LPG) Recovery Unit charging 32 MMSCFD gas;
• A new 10,000 BPCD Residuum Oil Supercritical Extraction (ROSE) Unit with a new 42 MMBTUH HHV heater;
• Expanded Diesel Hydrotreater Unit (DHTU), with a new 50 MMBTUH HHV helper heater;
• Revamped FCCU, increasing process throughput from 24,000 BPCD to capacity of approximately 28,400 BPCD;
• Modified Naphtha Hydrodesulfurizer (NHDS) Unit, with a new 10 MMBTUH HHV helper heater;
• Modified Continuous Catalytic Reforming (CCR) Unit, with a new 25 MMBTUH HHV helper heater and re-rating of the existing 141.8 MMBTUH heater to 155 MMBTUH;
• A new Naphtha Fractionation Column which will require steam from facility boilers; and
• Expansion of the Alkylation (ALKY) Unit to 6,500 BPD, using steam from existing boilers for process heat;
• The CDU Atmospheric Tower Heater will be modified from 200 MMBTUH capacity to 248 MMBTUH capacity.

• Construction of new tanks with VOC emissions up to 1.24 TPY will be authorized, but specifications for the new tanks are not yet known.

SECTION IV. EQUIPMENT AND EMISSIONS

HFTR is a Part 70 and PSD major facility for all criteria pollutants (including HAPs) except for PM_{10} / $PM_{2.5}$ emissions.

The West Refinery emission sources may be grouped into three primary categories, as shown in the following list.

1. Combustion stack emissions from heaters and boilers (GHG, VOC, CO, PM, NO_X, SO_2). The refinery fires only gaseous fuels.
2. Fugitive emissions from valves, fittings, equipment seals, and other sources (VOC, including VHAP).
3. Emissions from hydrocarbon service storage tanks (VOC, including VHAP).

Combustion Sources

Combustion sources at the refinery are referred to either as "grandfathered" or "non-grandfathered." Since all boilers and heaters are subject to NESHAP Subpart DDDDD, these designations are for state regulatory and NSPS purposes. The grandfathered units are fueled by refinery fuel gas, which is composed of residual "off gases" from various refinery process units. These units do not have emissions limits in terms of pollutants. The permitted units burn commercial grade natural gas, its equivalent, or RFG.

Fugitive VOC Leaks

The refinery fugitive equipment is controlled by the existing LDAR program. The basis for the emission calculations shown in HFTR's emission tables to follow in this section are shown individually on each table.

The following list groups all facility EUGs.

Grandfathered Fuel Burning Units

EUG 1, Existing Refinery Fuel Gas Burning Equipment

Non Grandfathered Fuel Burning Units

EUG 1A, PH-4
EUG 2, Boilers #7, #8, and #9
EUG 2A, Boiler No. 10
EUG 3, #2 PLAT PH-5 Heater
EUG 3A, #2 PLAT PH-6 Heater
EUG 4, Coker H-3 Heater
EUG 5, Coker B-1 Heater
EUG 6, MEK H-101 Heater
EUG 37, CDU H-2, CDU H-3, and LEU H-102 Heaters
EUG-39, ROSE Unit Heater
EUG-40, Hydrogen Plant Heater

Piping System Fugitives

EUG 7, Refinery Fugitive Emissions Subject to NSPS
EUGs 8 and 9, Existing Refinery Fugitive Emissions

Tank VOC Emissions

EUG 18, 63.640 (Subpart CC), Existing Group 1 Internal Floating Roof Storage Vessels
EUG 19, 63.640 (Subpart CC) Existing Group 1 External Floating Roof Storage Vessels
EUG 20, 63.640 (Subpart CC) Group 2 Storage Vessels
EUG 21, NSPS 60.110b (Subpart Kb) Internal Floating Roof Storage Vessels Storing Volatile Organic Liquids (VOL) Above 0.75 psia Vapor Pressure
EUG 22, NSPS 60.110b (Subpart Kb) External Floating Roof Storage Vessel Storing VOL Above 0.75 psia Vapor Pressure
EUG 23, NSPS 60.110b (Subpart Kb) Storing VOL Below 0.507 psia Vapor Pressure
EUG24, NSPS 60.110a (Subpart Ka) Storage Vessels Storing Petroleum Liquids Below 1.0 psia Vapor Pressure

EUG 25, NSPS 60.110 (Subpart K) Storage Vessels Storing Petroleum Liquids Below 1.0 RVP
EUG 26, Internal Floating Roof Storage Vessels Subject to OAC 252:100-39-41
EUG 27, External Floating Roof Storage Vessels Subject to OAC 252:100-39-41
EUG 28, Cone Roof Tanks

OTHERS

EUG 11, Lube Extraction Unit (LEU) and Coker Flare Subject to 40 CFR 63, Subpart GGG, J/Ja
EUG 11A, Platformer Flare Suject to 40 CFR 60, Subpart Ja
EUG 12, Wastewater Processing System
EUG 13, Truck Loading Dock Subject to 40 CFR 63, Subpart CC
EUG 14, Group 1 Process Vents Subject to 40 CFR 63, Subpart CC
EUG 15, Group 2 Process Vents Subject to 40 CFR 63, Subpart CC
EUG 16, Process Vent Subject to 40 CFR 63, Subpart UUU by April 11, 2005
EUG 17, Coker Enclosed Blowdown
EUG 29, Pressurized Spheres
EUG 30, Pressurized Bullet Tanks
EUG 31, Underground LPG Cavern
EUG 32, Non-Gasoline Loading Racks
EUG 33, LPG Loading Racks
EUG 34, Cooling Towers
EUG 35, Oil/Water Separators Subject to OAC 252:100-37-37 and 39-18
EUG 36, Natural Gas Fired Engines
EUG 38, Internal Combustion Engines Subject to 40 CFR 63, Subpart ZZZZ

New / Modified Units Emissions

Emissions from the ROSE Unit heater and Hydrogen Unit heater are based on continuous operation at rated heat input, using NSPS Subpart Ja limits for SO_2 (162 ppm in RFG, 3-hour basis and 60 ppm in RFG, 365-day rolling average), and all other factors from Tables 1.4-1 and 2 of AP-42 (7/98). A heating value of 1020 BTU/SCF was used for refinery fuel gas.

A. ROSE Unit Heater (EUG-39)

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
76 MMBTUH	NO_X	0.03	2.28	10.0
	CO	0.04	3.04	13.3
	VOC	0.0054	0.41	1.79
	SO_2	0.026 hourly 0.0098 annual	2.00	3.25
	PM_{10} / $PM_{2.5}$	0.0075	0.57	2.48
	GHG	163.29	12,410	54,356

B. New Hydrogen Plant Heater (EUG-40)

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
125 MMBTUH	NO_X	0.03	3.75	16.4
	CO	0.04	5.00	21.9
	VOC	0.0054	0.67	2.95
	SO_2	0.026 hourly 0.0098 annual	3.30	5.34
	PM_{10} / $PM_{2.5}$	0.0075	0.93	4.08
	GHG	163.29	20,411	89,401

C. ROSE Unit Heater Fugitive VOC Leaks (EUG-9)

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
New ROSE Heater	VOC Leakage at ROSE Unit Heater	gas valves	62	0.059	97%	0.11	0.48
		lt liq valves	76	0.024	97%	0.04	0.16
		flanges	292	0.00055	30%	0.11	0.49
		lt liq pumps	2	0.251	85%	0.08	0.33
		gas relief valves	6	0.35	97%	0.06	0.28
TOTALS						**0.42**	**1.82**

Control efficiencies are from TCEQ – Control Efficiencies for TCEQ Leak Detection and Repair Programs Revised 07/11 (APDG 6129v2).

D. New Hydrogen Plant Fugitive VOC Leaks (EUG-7)

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
New Hydrogen Plant	VOC Leakage at New Hydrogen Plant	gas valves	250	0.059	97%	0.44	1.94
		lt liq valves	50	0.024	97%	0.04	0.16
		flanges	610	0.00055	30%	0.23	1.03
		lt liq pumps	2	0.251	85%	0.08	0.33
		compressors	1	1.399	85%	0.21	0.92
		gas relief valves	2	0.35	97%	0.02	0.09
TOTALS						**1.02**	**4.47**

E. PDA / ROSE Unit Fugitive VOC Leaks (EUG-7)

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
PDA/ ROSE	VOC Leakage at PDA/ROSE Unit	gas valves	30	0.059	97%	0.05	0.23
		lt liq valves	30	0.024	97%	0.02	0.09
		flanges	100	0.00055	30%	0.04	0.17
		lt liq pumps	2	0.251	85%	0.08	0.33
		gas relief valves	4	0.35	97%	0.04	0.18
TOTALS						**0.23**	**1.01**

F. New Tanks (EUG-21, EUG-22, and EUG23)

New tanks will go into EUG-21 for internal floating roof tanks, EUG-22 for external floating roof tanks, or EUG 23 for cone roof tanks (low vapor pressure products such as diesel).

Existing Facility Emissions

Criteria pollutant emissions for EUG 1 are based on rated heat inputs, continuous operation, and Tables 1.4-1 and 2 of AP-42 (7/98) for all pollutants except SO_2, which is based on 162 ppm sulfur and 1020 BTU/SCF in the refinery fuel gas (RFG). The facility monitors the RFG system.

EUG 1: EXISTING REFINERY FUEL GAS BURNING EQUIPMENT & POTENTIAL TO EMIT (PTE)

Constr. Date	MM BTUH	EU	Point ID	NOx		CO		PM_{10}		SO_2		VOC	
				lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1961	160	201N	CDU H-1,N#7	44.6	195.4	13.7	60.6	1.21	5.33	4.80	21.03	0.88	3.89
1961	160	201S	CDU H-1,S#8	44.6	195.4	13.7	60.6	1.21	5.33	4.80	21.03	0.88	3.89
1957	36.7	206	Unifiner H-2	3.70	16.20	3.20	14.00	0.28	1.22	1.10	4.82	0.20	0.90
1957	59.5	207	Unifiner H-3	6.00	26.30	5.10	22.30	0.45	1.98	1.79	7.82	0.33	1.50
1957	86.8	209	#2 Plat PH-1/2	8.70	38.00	7.50	32.90	0.66	2.89	2.60	11.41	0.48	2.10
1957	36.3	210	#2 Plat PH-3	3.60	15.80	3.10	13.60	0.28	1.22	1.09	4.77	0.20	0.90
1971	25.6	214	#2 Plat PH-7	2.60	11.40	2.20	9.60	0.20	0.85	0.77	3.36	0.14	0.60
1963	22.4	242	LEU H101	2.20	9.60	1.92	8.30	0.17	0.75	0.67	2.94	0.12	0.53
1963	22.4	244	LEU H-201	2.20	9.60	1.90	8.30	0.17	0.75	0.67	2.94	0.12	0.53
1960	49.0	246	MEK H-2	4.9	21.5	4.20	18.4	0.37	1.63	1.47	6.44	0.27	1.20
Totals				**123.1**	**539.2**	**56.52**	**248.6**	**5.00**	**21.95**	**19.76**	**86.56**	**3.62**	**16.04**

CDU H-1 has two stacks, H-1 North and H-1 South.

EUG 1A: MODIFIED REFINERY FUEL GAS BURNING EQUIPMENT & POTENTIAL TO EMIT (PTE)

Constr. Date	MFR, BTUH, MM	EU	Point ID	NOx		CO		PM_{10}		SOx		VOC	
				lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1957	44.8	211	#2 Plat PH-4	4.48	19.62	3.76	16.48	0.34	1.49	1.16	1.92	0.25	1.08

EUG 2: NON-GRANDFATHERED BOILERS & PTE

CD	EU	Point ID	CO		NOx		PM_{10}		SOx		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1975	109	#7 Boiler*, 150 MMBTUH	12.6	55.2	30.00	131.4	1.12	4.90	3.90	17.08	0.83	3.62
1976	110	#8 Boiler*, 150 MMBTUH	12.6	55.2	30.00	131.4	1.12	4.90	3.90	17.08	0.83	3.62
1976	111	#9 Boiler*, 150 MMBTUH	12.6	55.2	30.00	131.4	1.12	4.90	3.90	17.08	0.83	3.62
TOTALS			**37.8**	**165.6**	**90.0**	**394.2**	**3.36**	**14.7**	**11.70**	**51.24**	**2.49**	**10.86**

* subject to NSPS Subpart J.

EUG 2A: BOILER SUBJECT TO NSPS Db and Ja

CD	EU	Point ID	CO		NOx		PM_{10}		SO_2		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2013	---	#10 boiler, 215 MMBTUH	18.06	79.10	12.88	39.00	1.63	7.16	5.59	9.23	1.18	5.18

Criteria pollutant emissions for EUG 3 & 3A are based on continuous operation at listed rated heat input, using factors taken from Tables 1.4-1 and 2 of AP-42 (7/98) with the exception of SO_X. SO_X emissions are based on continuous operation at rated heat input and the 162 ppm sulfur limit in NSPS Subpart J. PH-6 is not subject to NSPS Subpart J.

EUG 3: #2 PLAT PH-5 HEATER NSPS J (AUTHORIZED EMISSIONS IN TPY)

CD	EU	Point ID	CO	NOx	PM_{10}	SO_2	VOC
1990	212	#2 Plat PH-5 65.3 MMBTUH	23.55	28.04	2.13	7.43	1.54

EUG 3A: #2 PLAT PH-6 HEATER STATE (AUTHORIZED EMISSIONS IN TPY)

CD	EU	Point ID	CO	NOx	PM_{10}	SO_2	VOC
1957	213	#2 Plat PH-6 34.8 MMBTUH	12.55	14.94	1.14	3.96	0.82

Emissions for EUG 4 are based on continuous operation at rated heat input, using manufacturer's suggested emission factor for NO_X, VOC, and CO, NSPS Subpart Ja compliant fuel, and PM_{10} from Table 1.4-2 of AP-42 (7/98).

EUG 4: COKER H-3 HEATER & PTE

CD	EU	Point ID	CO		NOx		PM_{10}		SO_2		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1995	224	Coker H-3, 32.2MMBTUH	2.70	11.85	3.22	14.10	0.25	1.07	0.84	1.38	0.18	0.78

Emissions for EUG 5 and 6 are based on continuous operation at rated heat input, using 162 ppm Subpart J for SO_2, and all other factors from Tables 1.4-1 and 2 of AP-42 (7/98).

EUG 5: COKER B-1 HEATER & PTE

CD	EU	Point ID	CO		NOx		PM_{10}		SO_2		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1992	225	Coker B-1, 60 MMBTUH	5.04	22.08	6.00	26.28	0.46	2.00	5.85	25.63	0.33	1.45

EUG 6: MEK H-101 HEATER

CD	EU	Point ID	CO		NOx		PM_{10}		SO_2		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1977	245	MEK H-101, 81 MMBTUH	6.80	29.8	8.10	35.5	0.62	2.70	2.11	9.24	0.45	1.95

EUGs 7, 8, and 9: REFINERY FUGITIVE GROUPS & PTE

Emission factors are from EIIP Volume II (11/29/96) Table 4.4-4, and are related to the type of service for each component. The following estimates are from the facility's 2001 annual emission inventory, as submitted to DEQ. Because the refinery is a dynamic operation, components are shifted in use, added or deleted, or replaced continuously. Thus, the following listing reflects estimates of components in place, and is not an actual count.

EUG 7 (NSPS)	EU	Equipment Point ID	Estimated Number of Components		VOC	
					lb/hr	TPY
	13557	LEU PsuedoRaffinate Stripper	Valves/HL	1715	0.87	3.81
			Flange/Connector/HL	3204	1.77	7.74
			Relief valves/HL	11	0.26	1.16
			Pump seals/HL	31	1.43	6.29
			Valves/Gas	664	0.43	1.89
			Relief valves/Gas	11	0.00	0.00
			Flange/Connector/Gas	1383	0.76	3.34
			Compressor seals/Gas	1	0.00	0.00
			Total		**5.52**	**24.23**
	13557	Perc Filter	Valves/LL	306	0.33	1.46
			Flange/Connector/LL	598	0.33	1.44
			Agitator/LL	7	0.00	0.00
			Pump seals/LL	5	1.28	5.40
			Pump seals/HL	36	1.67	7.30
			Relief valves/LL	2	0.05	0.21
			Valves/HL	572	0.29	1.27
			Relief valves/Gas	10	0.00	0.00
			Flange/Connector/Gas	13	0.00	0.03
			Valves/Gas	4	0.24	1.03
			Total		**4.19**	**18.14**

EUG 7 (NSPS)	EU	Equipment Point ID	Estimated Number of Components		VOC lb/hr	VOC TPY
	13557	#2 Platformer	Valves/LL	1168	1.49	6.54
			Flange/connector/LL	1227	0.38	1.64
			Pump seals/LL	19	0.50	0.21
			Relief valves/LL	12	0.29	1.26
			Valves/Gas	250	1.96	8.57
			Relief valves/Gas	4	0.00	0.00
			Flange/connector/Gas	300	0.19	0.82
			Total		**4.81**	**19.04**
	13557	FGRU West	Valves/Gas	300	0.35	1.55
			Valves/LL	225	0.11	0.47
			Valves, HL	50	0.03	0.11
			Pump seals/LL	9	0.34	1.48
			Flange/connector/LL	1186	0.46	2.00
			Compressors	3	0.63	2.76
			Relief valves/Gas	6	0.04	0.18
			Total		**1.96**	**8.55**
	13557	MEK Unit	Valves/LL	5560	5.37	23.42
			Flanges/Connectors/LL	8276	0.60	2.63
			Pump seals/LL	61	0.18	0.76
			Agitators/L	2	0.00	0.00
			Relief valves/LL	77	0.14	0.60
			Valves/Gas	1040	2.24	9.79
			Relief valves/Gas	11	0.00	0.00
			Flange/Connector/Gas	837	0.03	0.13
			Compressor seals/Gas	2	0.00	0.00
			Total		**8.55**	**37.44**

EUG 8 (MACT)	EU	Equipment Point ID	Estimated Number of Components		VOC	
					lb/hr	TPY
	13557	Coker	Valves/LL	224	0.18	0.80
			Flange/ Connector/LL	134	0.07	0.32
			Pump seals/LL	7	0.00	0.00
			Relief valves/LL	2	0.05	0.21
			Valves/HL	2	0.00	0.00
			Valves/Gas	348	0.57	2.48
			Relief valves/Gas	4	0.00	0.00
			Flange/Connector/Gas	288	0.19	0.82
			Compressor seals/Gas	2	0.00	0.00
			Total		**1.06**	**4.63**
	13557	CDU	Valves/LL	1186	0.94	4.11
			Valves/HL	39	0.00	0.00
			Flange/Connector/LL	860	0.00	0.00
			Pump seals/LL	36	0.00	0.00
			Relief valves/LL	10	0.00	0.00
			Valves/Gas	821	1.78	7.81
			Relief valves/Gas	16	0.00	0.00
			Flange/Connector/Gas	404	0.22	0.97
			Compressor seals/Gas	2	0.24	1.06
	13557	Truck Loading Dock	Valves/LL	387	0.39	1.71
			Flange/Connector/LL	508	0.28	1.23
			Relief valves/LL	1	0.00	0.00
			Pump seals/LL	5	0.00	0.00
			Valves/Gas	16	0.00	0.00
			Relief valves/Gas	2	0.00	0.00
			Flange/Connectors/Gas	2	0.00	0.00
			Total		**0.67**	**2.94**

EUG 8 (MACT)	EU	Equipment Point ID	Estimated Number of Components		VOC	
					lb/hr	TPY
	13557	Tank Farm	Valves/LL	2564	4.73	20.72
			Agitator/LL	17	0.00	0.00
			Relief valves/LL	32	0.77	3.37
			Flange/Connectors/LL	2753	1.52	6.65
			Pump seals/LL	43	0.08	0.33
			Valves/Gas	460	0.42	1.83
			Relief valves/Gas	52	0.00	0.00
			Flange/Connectors/Gas	353	0.19	0.85
			Compressor seals/Gas	1	0.00	0.00
			Total		**7.71**	**33.75**
	13557	Unifiner	Valves/LL	84	0.15	0.66
			Flanges/Connector/LL	533	0.29	1.29
			Pump seals/LL	1	0.00	0.00
			Valves/Gas	547	1.67	7.32
			Relief valves/Gas	2	0.00	0.00
			Flange/Connector/Gas	338	0.19	0.82
			Total		**2.30**	**10.09**
	13557	#5 Boilerhouse	Valves/Gas	131	0.61	2.69
			Flange/Connector/Gas	66	0.04	0.16
			Total		**0.65**	**2.85**
	13557	Butane Splitter Unit	Valves/LL	360	3.05	13.34
			Flange/Connector/LL	288	0.16	0.70
			Pump seals/LL	11	0.00	0.00
			Relief valves/LL	6	0.00	0.00
			Valves/Gas	157	0.75	3.27
			Relief valves/Gas	8	0.00	0.00
			Flange/Connector/Gas	114	0.06	0.28
			Total		**4.02**	**17.59**
	13557	LERU	Valves/LL	220	1.02	4.48
			Flange/Connector/LL	153	0.08	0.37
			Pump seals/LL	4	0.00	0.00
			Valves/Gas	191	0.60	2.66
			Relief valves/Gas	3	1.06	4.63
			Flange/Connector/Gas	114	0.06	0.27
			Total		**2.82**	**12.41**
EUG 9 (State)	**EU**	**Equipment Point ID**	**Estimated Number of Components**		**VOC**	
	13557	MEROX Unit	Valves/HL	69	0.04	0.15
			Flange/Connector/LL	208	0.12	0.50
			Pump seals/HL	1	0.05	0.20
			Valves/Gas	35	2.07	9.06
			Flange/Connector/Gas	104	0.06	0.25
			Total		**2.34**	**10.16**
Total of EUGs 7, 8, 9					**53.7**	**234.54**

EUG 11: Lube Extraction Unit (LEU) and Coker Flare Subject to 40 CFR 60, Subpart GGG (1)(2); 40 CFR 60, Subpart J/Ja

Emissions for EUG 11 are based on continuous operation, using emission factors from Table 13.5-1 of AP 42 (9/91) and evaluating only the pilot. This is a minimal estimate, not full PTE.

CD	EU	Point ID	Equipment	VOC		CO		NOx		SO_2	
				lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1976	269	LEU Flare	John Zink EEF-QS-SA-18 smokeless flare tip	0.04	0.19	0.12	0.51	0.04	0.19	0.12	0.51
	268	Coker Flare	John Zink EEF-QS-30 smokeless flare tip	0.13	0.55	0.33	1.5	0.06	0.27	0.12	0.5
Total				**0.17**	**0.74**	**0.45**	**2.01**	**0.10**	**0.46**	**0.24**	**1.01**

(1) Group 1 vents go to this flare only under emergency conditions.

(2) Performance testing required by NSPS Subpart GGG also meets requirements of NESHAP Subpart CC (allowed Group 1 vents to flare).

EUG 11a: Platformer Flare Subject to 40 CFR 60, Subpart Ja

Emissions for EUG 11a are based on continuous operation, using emission factors from Table 13.5-1 of AP 42 (9/91) and evaluating actual emissions.

CD	EU	Point ID	Equipment	VOC		CO		NOx		SO_2	
				lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1960	267	Plat Flare	John Zink EEF-QS-30 smokeless flare tip	8.5	37.3	3.7	16.4	0.7	3.02	1.74	7.66

EUG 12: Wastewater Processing System

VOC emissions for EUG 12 are based on EPA's Water Software Program No. 9. Input data combine model defaults and calendar year 2005 emission inventory.

EU	Point ID	Equipment	VOC	
			lb/hr	TPY
15943	WPU-1	Wastewater Processing Unit and Open Sewers	35	153

EUG 14: Group 1 Process Vents Subject to 40 CFR 63, Subpart CC

EU	Equipment Point ID	Control Device
N/A	CDU Vacuum Tower Vent	CDU H-2
N/A	LEU T-201 Hydrostripper Tower Vent	LEU H-102
N/A	Coker Enclosed Blowdown Vent	Platformer Flare, Coker Flare

EUG 15: Group 2 Process Vents Subject to 40 CFR 63, Subpart CC

EU	Equipment/ Point ID
N/A	MEK T-7 Vent
N/A	LEU T-101 Vent
N/A	LEU D-101 Vent

EUG 16: Process Vent Subject to 40 CFR 63, Subpart UUU

EU	Equipment Point ID
N/A	#2 Platformer Catalytic Reforming Vent

EUG 18: 63.640 (Subpart CC), Existing Group 1 Internal Floating Roof Storage Vessels. Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

Const Date	Tank Nos.	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
1916	13	6333	Tk13	Crude Oil	0.06	0.27
1916	21	6336	Tk21	Gasoline	0.70	3.07
1916	22	6337	Tk22	Gasoline	0.98	4.32
1940	31	6340	Tk31	Gasoline	0.76	3.33
1917	153	6346	Tk153	Platformate	0.66	2.88
1922	186	6348	Tk186	Crude Oil	0.09	0.39
1922	187	6349	Tk187	Crude Oil	0.12	0.51
1922	188	13592	Tk188	Crude Oil	0.05	0.22
1917	242	6359	Tk242	Out of Service	---	---
1917	244	6360	Tk244	LEF	1.42	6.2
1970	473	6387	Tk473	MEK	0.18	0.77
1979	474*	6388	Tk474	MEK	0.18	0.77
1965	502	1359	Tk502	Naphtha	1.11	4.85
1948	742	6392	Tk742	Out of Service	---	---
Total					**6.31**	**27.58**

* Although Tank 474 was constructed in 1979 and is subject to NSPS Subpart Ka, the Group 1 MACT requirements supersede those requirements per the overlap provisions of 40 CFR 63.640(n)(5).

EUG 19: 63.640 (Subpart CC) Existing Group 1 External Floating Roof Storage Vessels Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001 shown. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

Const Date	Tank #	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
1973	199	6353	Tk199	Out of Service	---	---
1946	307	6367	Tk307	Coker LPD	2.03	8.88
1972	750	6396	Tk750	Out of Service	---	---
1949	752	6398	Tk752	Gasoline	3.27	14.33
1950	755	6399	Tk755	Gasoline	5.37	23.51
1953	779	6401	Tk779	Out of Service	---	---
1965	874	6405	Tk874	Crude Oil	0.93	4.07
Total					**11.60**	**50.79**

EUG 20: 63.640 (Subpart CC) Group 2 Storage Vessels

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents. All tanks were constructed before 1970.

Tank #	EU	Point ID	Current Service	VOC	
				lb/hr	TPY
6	20128	Tk6	Kerosene	0.02	0.10
30	13559	Tk30	Kerosene	0.13	0.56
41	1356	Tk41	Out of Service	---	---
50	13561	Tk50	Naphtha wash	0.05	0.22
51	13562	Tk51	Out of Service	---	---
155	13563	Tk155	Out of Service	---	---
181	20129	Tk181	Jet fuel	0.01	0.04
190	6351	Tk190	Kerosene	0.34	1.50
277	13573	Tk277	Slop Oil	1.03	3.02
279	6364	Tk279	Out of Service	---	---
281	13574	Tk281	Slop Oil	0.59	2.57
283	13576	Tk283	Out of Service	---	---
312	6368	Tk312	Out of Service	---	---
315	6370	Tk315	Out of Service	---	---
401	6375	Tk401	Kerosene	0.15	0.68
582	13596	Tk582	Slop Oil	0.95	4.15
696	NA	Tk696	Slop Oil	0.28	1.20
747	6393	Tk747	Out of Service	---	
751	5397	Tk751	Out of Service	---	
Totals				**3.55**	**14.04**

(1) Certain tanks are affected facilities under rules in addition to CC and are listed in EUGs addressing those rules. The alternate EUG is shown here to direct the reader to the listing of estimated emissions in their respective EUGs.
(2) Centrifuge Charge.

EUG 21: NSPS 60.110b (Subpart Kb) Internal Floating Roof Storage Vessels Storing Volatile Organic Liquids (VOL) Above 0.75 psia Vapor Pressure

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

Const Date	Tank #	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
1988	25	6338	Tk25	Naphtha	0.07	0.30
1995	1061	13594	Tk1061	Out of service	--	--
2000	1070	20126	Tk1070	Slop Oil	0.89	3.89
2004	1080	NA	Tk1080	Slop Oil	0.66	2.90
1998	782	6402	Tk782	Out of service	--	--
Totals					**1.62**	**7.09**

EUG 22: NSPS 60.110b (Subpart Kb) External Floating Roof Storage Vessel Storing VOL Above 0.75 psia Vapor Pressure

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

Constr Date	Tank #	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
1994	583	13591	Tk583	Out of service	--	--

EUG 23: NSPS 60.110b (Subpart Kb) Storing Volatile Organic Liquids below 0.507 psia Vapor Pressure

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

Const Date	Tank #	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
2010	27	13588	Tk27	Residual Oils	-	0.73
1917	84	N/A	Tk84	Out of Service	-	-
1917	85	N/A	Tk85	Out of Service	-	-
2012	189	6350	Tk189	Out of Service	-	-
2009	405	6377	TK405	Diesel	-	1.68
2009	406	13578	TK406	Diesel	-	1.68
1985	997	13588	Tk997	Out of Service	-	-
1985	998	13589	Tk998	Out of Service	-	-
1987	1002	6406	Tk1002	Lube Oil	0.66	2.93
1989	1005	N/A	Tk1005	Out of Service	-	-
1990	1012	15950	Tk1012	Furfural/ Water	0.00	0.01
2012	1038	N/A	Tk1038	Sewer Storm water	-	2.72
1993	1039	16561	Tk1039	Sewer Storm water	0.00	0.01
2013	157	14307	Tk157	Lube Oil	0.01	0.01
Totals					**0.67**	**9.77**

EUG 24: NSPS 60.110a (Subpart Ka) Storage Vessels Storing Petroleum Liquids Below 1.0 psia Vapor Pressure

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

Const Date	Tank #	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
1980	224	13569	Tk224	Extract	0.00	0.04
1988	277	13573	Tk277	Slop Charge	0.88	3.85
1979	881	NA	Tk881	Slop Wax	0.13	0.58
1983	890	NA	Tk890	Out of Service	-----	----
1982	992	NA	Tk992	Out of Service	-----	----
1982	993	NA	Tk993	Out of Service	-----	----
Totals					**1.01**	**4.47**

EUG 25: NSPS 60.110 (Subpart K) Storage Vessels Storing Petroleum Liquids below 1.0 Psia Vapor Pressure

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

Const Date	Tank #	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
1974	152	6324	Tk152	Out of Service	---	---
1973	158	13565	Tk158	Gas Oil	1.52	6.60
1978	472	NA	Tk472	Lube Oil	0.00	0.01
1976	983	NA	Tk983	Lube Oil	0.00	0.01
1976	984	NA	Tk984	Out of Service	---	---
1976	986	NA	Tk986	Wax	0.00	0.01
1976	987	NA	Tk987	Wax	0.00	0.01
Total					**1.52**	**6.64**

EUG 27: External Floating Roof Storage Vessels Subject to OAC 252:100-39-41

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents.

CD	Tank #	EU	Point ID	Current Service	VOC	
					lb/hr	TPY
1957	314	6369	Tk314	Out of service	---	---
Totals					---	---

EUG 28: Fixed Roof Tanks

Emissions are calculated using Tanks 4.0 and the "current service" information, capacity, and throughput for calendar year 2001. Tanks may be used in any manner consistent with the requirements for this EUG, and are not bound by the listed current contents. All tanks were constructed before 1970.

EU	Point ID	Current Service	Capacity (bbls)	VOC	
				lb/hr	TPY
20127	Tk1	Out of Service	1698	----	----
Tk9	Tk9	Extract	7000	0.03	0.12
Tk10	Tk10	Out of Service	7000	----	----
Tk11	Tk11	Out of Service	7000	----	----
6334	Tk15	Lube Oil	7000	0.00	0.00
6335	Tk16	Lube Oil	7000	0.00	0.01
Tk23	Tk23	Lube Oil	7000	0.02	0.09
Tk26	Tk26	Lube Oil	55000	0.04	0.19
20130	Tk28	Coker Chg	38000	0.00	0.01
6339	Tk29	Out of Service	55000	----	----
Tk33	Tk33	Lube Oil	55000	0.00	0.00
Tk34	Tk34	Out of Service	55000	----	----
6342	Tk35	Out of Service	55000	----	----
6343	Tk36	Gasoil	55000	0.03	0.14
Tk38	Tk38	Gasoil	1890	0.46	1.96
Tk45	Tk45	Wax	4200	0.00	0.00
Tk46	Tk46	Wax	4200	0.00	0.00
Tk52	Tk52	Out of Service	1890	----	----
Tk53	Tk53	Wax	1890	0.00	0.00
Tk54	Tk54	Out of Service	1890	----	----
Tk62	Tk62	Wax	4200	0.00	0.00
Tk65	Tk65	Out of Service	1890	----	----
Tk66	Tk66	Out of Service	1890	----	----
Tk68	Tk68	Wax	1890	0.00	0.00
Tk69	Tk69	Out of Service	1890	----	----
Tk71	Tk71	Lube Oil	5680	0.01	0.04
Tk72	Tk72	Lube Oil	5680	0.01	0.04
Tk73	Tk73	Lube Oil	5680	0.01	0.04
Tk74	Tk74	Lube Oil	5680	0.00	0.00
Tk75	Tk75	Out of Service	1890	----	----
Tk76	Tk76	Lube Oil	1890	0.01	0.04
Tk79	Tk79	Out of Service	1890	----	----
Tk80	Tk80	Extract	1890	0.01	0.03
Tk81	Tk81	Out of Service	1890	----	----
Tk83	Tk83	Extract	1890	0.00	0.01
Tk132	Tk132	Extract	1800	0.00	0.01
Tk133	Tk133	Extract	1800	0.01	0.04

EU	Point ID	Current Service	Capacity (bbls)	VOC	
				lb/hr	TPY
Tk134	Tk134	Extract	7000	0.04	0.18
6344	Tk151	Out of Service	7000	----	----
13564	Tk156	Lube Oil	55000	0.07	0.30
15944	Tk159	Lube Oil	55000	0.01	0.02
Tk192	Tk192	Lube Oil	52300	0.01	0.02
15945	Tk193	Coker Chg	52730	0.01	0.02
13567	Tk194	Lube Oil	53100	0.01	0.05
Tk195	Tk195	Lube Oil	55000	0.01	0.02
Tk196	Tk196	Lube Oil	55000	0.00	0.00
6355	Tk215	Out of Service	50914	----	----
15946	Tk217	Diesel	7000	0.03	0.14
13568	Tk218	Out of Service	7000	----	----
Tk223	Tk223	Extract	7000	0.03	0.15
Tk227	Tk227	Extract	7000	0.03	0.15
Tk228	Tk228	Wax	1890	0.00	0.00
Tk229	Tk229	Out of Service	1890	----	----
Tk232	Tk232	Wax	1890	0.00	0.00
Tk233	Tk233	Wax	1890	0.00	0.00
Tk234	Tk234	Wax	1890	0.00	0.00
Tk235	Tk235	Wax	1890	0.00	0.00
Tk236	Tk236	Lube Oil	1890	0.00	0.00
Tk237	Tk237	Out of Service	1890	----	----
Tk240	Tk240	Out of Service	1500	----	----
Tk252	Tk252	Lube Oil	7000	0.00	0.00
Tk264	Tk264	Out of Service	1890	----	----
Tk265	Tk265	Out of Service	1890	----	----
Tk266	Tk266	Extract	1890	0.01	0.02
Tk267	Tk267	Out of Service	1890	----	----
Tk271	Tk271	Out of Service	1890	----	----
6363	Tk272	Out of Service	1890	----	----
Tk273	Tk273	Lube Oil	7000	0.04	0.18
Tk274	Tk274	Lube Oil	7000	0.04	0.16
Tk275	Tk275	Lube Oil	7000	0.05	0.22
Tk276	Tk276	Gasoil	7000	0.11	0.49
6364	Tk279	Out of Service	7000	----	----
6356	Tk280	Out of Service	7000	----	----
6366	Tk284	Out of Service	7000	----	----
Tk305	Tk305	Lube Oil	7000	0.00	0.01
Tk317	Tk317	Lube Oil	7000	0.02	0.10
Tk318	Tk318	Lube Oil	7000	0.02	0.11
Tk319	Tk319	Out of Service	1890	----	----
Tk320	Tk320	Out of Service	1890	----	----
Tk321	Tk321	Lube Oil	1890	0.00	0.01

EU	Point ID	Current Service	Capacity (bbls)	VOC	
				lb/hr	TPY
Tk322	Tk322	Out of Service	1890	----	----
6371	Tk323	Out of Service	7000	----	----
Tk327	Tk327	Out of Service	1890	----	----
Tk328	Tk328	Lube Oil	1890	0.00	0.00
Tk329	Tk329	Lube Oil	1890	0.00	0.00
Tk331	Tk331	Lube Oil	7000	0.00	0.00
Tk332	Tk332	Lube Oil	7000	0.00	0.00
Tk335	Tk335	Out of Service	1890	----	----
Tk390	Tk390	Extract	7000	0.02	0.09
Tk391	Tk391	Extract	5000	0.02	0.09
Tk392	Tk392	Extract	5000	0.04	0.18
Tk393	Tk393	Out of Service	1000	----	----
Tk394	Tk394	Out of Service	1120	----	----
Tk396	Tk396	Out of Service	5940	----	----
Tk397	Tk397	Out of Service	5940	----	----
6373	Tk398	Out of Service	2600	----	----
6374	Tk399	Out of Service	2600	----	----
Tk471	Tk471	Wax	3780	0.00	0.00
Tk509	Tk509	Out of Service	4000	----	----
6389	Tk510	Out of Service	1890	----	----
6390	Tk511	Out of Service	1890	----	----
6391	Tk519	Out of Service	4000	----	----
Tk645	Tk645	Extract	1500	0.01	0.02
Tk646	Tk646	Lube Oil	1500	0.01	0.02
Tk649	Tk649	Out of Service	1008	----	----
Tk650	Tk650	Extract	10000		
Tk675	Tk675	Out of Service	1500	----	----
Tk691	Tk691	Extract	2400	0.01	0.02
Tk692	Tk692	Lube Oil	2400	0.00	0.00
Tk693	Tk693	Lube Oil	2400	0.00	0.00
Tk694	Tk694	Lube Oil	2400	0.00	0.00
Tk700	Tk700	Lube Oil	15000	0.00	0.00
13585	Tk701	Lube Oil	15000	0.00	0.00
13584	Tk702	Wax	7000	0.00	0.00
6403	Tk799	Out of Service	1890	----	----
Tk800	Tk800	Wax	7000	0.00	0.00
15958	Tk801	Lube Oil	15000	0.00	0.00
13586	Tk802	Lube Oil	15000	0.00	0.00
15949	Tk803	Out of Service	15000	----	----
Tk807	Tk807	Wax	4200	0.00	0.00
Tk828	Tk828	Lube Oil	30000	0.00	0.00
Tk829	Tk829	Lube Oil	30000	0.00	0.00
Tk830	Tk830	Lube Oil	30000	0.00	0.00

EU	Point ID	Current Service	Capacity (bbls)	VOC	
				lb/hr	TPY
Tk831	Tk831	Lube Oil	30000	0.00	0.00
Tk835	Tk835	Out of Service	2000	----	----
6404	Tk838	Out of Service	2000	----	----
Tk847	Tk847	Wax	2032	0.00	0.00
Tk848	Tk848	Wax	2032	0.00	0.00
Tk851	Tk851	Out of Service	2088	----	----
Tk852	Tk852	Out of Service	4025	----	----
Tk853	Tk853	Out of Service	4025	----	----
Tk854	Tk854	Resid	4025	0.00	0.00
Tk855	Tk855	Out of Service	4025	----	----
Tk856	Tk856	Resid	4025	0.00	0.00
Tk857	Tk857	Out of Service	2011	----	----
Tk861	Tk861	Out of Service	1000	----	----
Tk865	Tk865	Out of Service	1890	----	----
Tk867	Tk867	Lube Oil	1675	0.00	0.00
13587	Tk870	Furfural	5300	0.00	0.00
Tk875	Tk875	Wax	2090	0.00	0.00
Tk876	Tk876	Out of Service	3000	----	----
Tk877	Tk877	Wax	2090	0.00	0.00
Tk878	Tk878	Slop Oil	2090		
Tk879	Tk879	Out of Service	2090	----	----
Tk880	Tk880	Slop Oil	3000		
Tk882	Tk882	Lube Oil	20000	1.4	6.1
Tk883	Tk883	Lube Oil	1000	0.00	0.00
Tk884	Tk884	Lube Oil	1000	0.00	0.00
Tk885	Tk885	Lube Oil	1000	0.00	0.00
Tk886	Tk886	Lube Oil	10492	0.02	0.10
Tk887	Tk887	Lube Oil	19500	0.02	0.10
Tk888	Tk888	Lube Oil	10492	0.00	0.00
Tk891	Tk891	Out of Service	1000	----	----
Tk893	Tk893	Wax	10500	0.00	0.00
Tk898	Tk898	Out of Service	2455	----	----
Tk913	Tk913	Out of Service	2090	----	----
Tk914	Tk914	Out of Service	2090	----	----
Tk916	Tk916	Out of Service	2090	----	----
Tk918	Tk918	Extract	30000	0.11	0.48
Tk921	Tk921	Lube Oil	2094	0.01	0.03
Tk922	Tk922	Lube Oil	3058	0.01	0.03
Tk923	Tk923	Lube Oil	2084	0.00	0.00
Tk924	Tk924	Lube Oil	4455	0.00	0.00
Tk925	Tk925	Lube Oil	4455	0.00	0.00
Tk926	Tk926	Lube Oil	1313	0.00	0.00
Tk927	Tk927	Extract	1313	0.00	0.00

EU	Point ID	Current Service	Capacity (bbls)	VOC	
				lb/hr	TPY
Tk928	Tk928	Lube Oil	4455	0.00	0.00
Tk929	Tk929	Lube Oil	4455	0.00	0.00
Tk930	Tk930	Lube Oil	1313	0.00	0.00
Tk931	Tk931	Lube Oil	1313	0.00	0.00
Tk932	Tk932	Lube Oil	3058	0.00	0.00
Tk933	Tk933	Lube Oil	1000	0.00	0.00
Tk934	Tk934	Out of Service	1000	----	----
Tk935	Tk935	Out of Service	1000	----	----
Tk936	Tk936	Out of Service	1000	----	----
Tk937	Tk937	Out of Service	1000	----	----
Tk938	Tk938	Out of Service	1000	----	----
Tk939	Tk939	Out of Service	1000	----	----
Tk940	Tk940	Out of Service	1000	----	----
Tk941	Tk941	Out of Service	1000	----	----
Tk942	Tk942	Out of Service	1000	----	----
Tk943	Tk943	Out of Service	1000	----	----
Tk944	Tk944	Out of Service	1000	----	----
Tk955	Tk955	Out of Service	1000	----	----
TkAGT1	TkAGT1	Slop Diesel	2000	0.13	0.55
TkAGT2	TkAGT2	Slop Diesel	1000	0.08	0.36
TkAGT3	TkAGT3	Slop Diesel	1000	0.09	0.41
TkAGT4	TkAGT4	Slop Diesel	2000	0.14	0.62
Totals				**3.30**	**14.32**

EUG 29: Pressurized Spheres

There are no emissions from these pressurized vessels. Fugitive emissions from associated piping are included in the calculations for EUG 8.

Tank #	Point ID	Nominal Capacity (bbls)	Construction Date
Tk 585	Tk585	19,744	1947
Tk 586	Tk586	19,744	1947
Tk 587	Tk587	19,744	1947
Tk 588	Tk588	19,744	1949
Tk 589	Tk589	19,744	1949
Tk 788	Tk788	19,744	1955
Tk 789	Tk789	19,744	1955
Tk 797	Tk797	19,744	1956
Tk 798	Tk798	19,744	1956
Tk 804	Tk804	5,117	1957
Tk 805	Tk805	5,117	1957
Tk 806	Tk806	5,117	1957

EUG 30: Pressurized Bullet Tanks
There are no emissions from these pressurized vessels. Fugitive emissions from associated piping are included in the calculations for EUG 8.

Tank #	Point ID	Nominal Capacity (bbls)	Const Date
Tk 791	Tk791	720	1955
Tk 792	Tk792	720	1955
Tk 793	Tk793	720	1955
Tk 794	Tk794	720	1955
Tk 795	Tk795	720	1955
Tk 1007	Tk1007	1,430	1990
Tk 1008	Tk1008	1,430	1990

EUG 31: Underground LPG Cavern
There are no vents or normal emissions from this unit that was constructed in 1961. Fugitive emissions from associated piping are included in the calculations for EUG 8. This "vessel" predates federal and state rules and regulations. Since it is pressurized, it satisfies the requirements of OAC 252:100-39-41. Pressurized vessels do not meet the definition of storage vessels in MACT CC, per 40 CFR 63.641.

CD	Tank #	EU	Point ID
1961	Tk 900	NA	Tk900

EUG 32: Non-Gasoline Loading Racks
Emission estimates are based on engineering estimates and calculations provided by the facility, using throughput information from calendar year 2001.

CD	EU	Equipment Point ID	VOC	
			lb/hr	TPY
1937	N/A	Black Oil Truck Loading Rack	0.004	0.02
1993	N/A	Extract Truck Loading Rack	0.44	1.92
1930	N/A	Extract Rail Loading Rack	0.76	3.34
1979	N/A	Wax Truck Loading Rack	0.00	0.00
1917	N/A	Wax Rail Loading Rack	0.00	0.00
1967	N/A	LOB Rail Loading Rack	0.15	0.66
1978	N/A	LOB Truck Loading Rack	0.10	0.44
1962	N/A	Resid Truck Loading Rack	0.01	0.05
1986	N/A	Diesel Rail Loading Rack	0.01	0.02
		VOC totals	**1.47**	**6.45**
			PM_{10}	
			PPH	**TPY**
1991	18371	Coke Truck Loading Area	0.20	0.90

EUG 33: Liquid Petroleum Gas (LPG) Loading Racks
These are high pressure LPGs with no emissions from piping, etc. Emissions from residual material in the tubing after uncoupling have not been estimated.

CD	EU	Equipment/Point ID
1956	N/A	LPG Truck Loading Rack

EUG 34: Cooling Towers
Emissions were estimated using Table 5.1-2 of AP-42 (1/95), for VOCs and Fire 6.25 based on Table 13.4-1 of AP-42 (1/95). These towers are subject to 40 CFR Part 63, Subpart CC.

EU	Point ID	Equipment
15942	CT2	LEU/MEK Cooling Tower
15942	CT3	Coker/#2 Platformer Cooling Tower
15942	CT4	LEU/MEK Cooling Tower
15942	CT6	PDA/# 5 BH Cooling Tower
15942	CT8	CDU Cooling Tower
15942	CT9	BSU Cooling Tower
15942	3A	Plat Cooling Tower
15942	3B	Coker Cooling Tower

EUG 35: Oil/Water Separators Subject to OAC 252:100-37-37 and 39-18
Emissions are calculated using WATER9 and wastewater throughput data for calendar year 2010.

EU	Point ID	Equipment	VOC	
			lb/hr	TPY
N/A	D-40	Separator at Lube Packaging	0.03	0.12
N/A	D-41	Separator at Lube Blending and Tankage	0.03	0.12
N/A	D-42	Separator from MEK/Lube Unit	0.03	0.12
N/A	S1-51	Separator at Belt Press (sealed)	0.03	0.12
N/A	Primary Clarifier	Primary Clarifier at WPU	EUG 12 (1)	
6332	Tk 532	Separator at T&S (sealed)	0.01	0.05
6331	Tk 533	Separator at T&S (sealed)	0.01	0.05
Totals			**0.14**	**0.58**

(1) Reported in EUG 12 previously.

EUG 36: Spark Ignition Internal Combustion Engines Subject to 40 CFR Part 63 Subpart ZZZZ

These engines are subject to 40 CFR 63 Subpart ZZZZ. Engines 256 and 257 are natural gas-fired RICE engines that were required to meet the applicable requirements of this rule by June 25, 2007. Engines 208, 241, 245, 255 and 258 are existing natural gas-fired RICE engines that were required to meet the applicable requirements of this rule by October 19, 2013. PTE is based on listed rated engine horsepower and a maximum 500 hours per year for each of the emergency units, using emission factors from Table 3.4-1 of AP-42 (10/96), and assuming a maximum sulfur content of 0.5%$_W$. Factors from Table 3.2-1 of AP-42 (7/00) and continuous operation are assumed for engines 256, 257, 208, 241, 245, 255, and 258. The three emergency use engines are only subject to work practice standards. In addition, no initial notification is necessary for the emergency engines.

Engine Number	EU	Point ID	Horsepower
Non-Emergency 4SRB >500 HP			
EG-5152	256	#6 CT Circulation Pump	615
Emergency 4SRB			
EG-6349		Emergency	36
EG-5879		Emergency	69
EG-6235		Emergency	175
	Total horsepower		**895**

Pollutant	Emission factor Lb/MMBtu	Emissions	
		lb/hr	TPY
CO	3.72	23.31	71.97
NO_X	2.21	13.80	42.75
PM_{10}	0.0194	0.012	0.38
SO_2	5.88×10^{-4}	0.004	0.01
VOC	0.0296	0.19	0.57

EUG 37: CDU H-2, CDU H-3, LEU H-102, PH-6 Heaters

These units have been subject to several permit actions concerning aspects of the combustion process, but no specific emissions have been authorized. The CDU and LEU units have NO_X estimated at 0.1 lb/MMBtu. The CDU SO_2 factor is estimated at 0.03 lbs/MMBtu, and the LEU SO_2 factor is estimated at 0.03 lbs/MMBtu. Factors identified as "estimates" and maximum heat input ratings are taken from permit applications submitted by the facility. RFG to the CDU and LEU is estimated to have 900-1000 BTU/CF. All other factors used in calculating PTE are taken from the appropriate portions of Tables 1.4-1 and 2 of AP-42 (7/98). PTE calculations in the second table following use continuous operation of each unit, combined with the appropriate factors as described above. Note that none of the permit actions changed the status of these units as "existing" sources under Subchapter 31 or NSPS Subpart J.

EU	Point ID	Original Const. Date	Permit Date	Max Heat Input (MMBTUH)
202	CDU H-2	1961	August 11, 1989	80.0
203	CDU H-3	1961	August 11, 1989	43.2
243N	LEU H-102 N	1963	August 11, 1989	150
243S	LEU H-102 S	1963		

	CO		NO_X		PM_{10}		SO_2		VOC	
EU	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
202	6.64	29.1	6.72	29.4	0.60	2.63	2.02	8.83	0.44	1.91
203	4.27	18.7	4.32	18.9	0.39	1.71	1.30	5.68	0.28	1.22
243	14.8	64.9	15.0	65.7	1.34	5.87	4.50	19.71	0.97	4.25
Totals	25.7	113	26.0	114	2.33	10.2	7.82	34.22	1.69	7.38

EUG 38: Compression Ignition Internal Combustion Engines Subject to 40 CFR Part 63 Subpart ZZZZ

The engines are in emergency service, and no initial notification is necessary for the emergency engines. The engines are existing emergency use CI RICE and are subject to work practice standards under Subpart ZZZZ by the compliance date of May 3, 2013. Emission estimates for the engines are calculated using factors for Table 3.4-1 of AP-42 (10/96), listed rated engine horsepower, and the 500-hour criterion associated with this activity. These are emission estimates only as there are no emission limitations for existing emergency CI RICE.

Engine Number	HP	USE	Fuel
EG-6192	603	Emergency (portable)	Diesel
EG 6217	603	Emergency	Diesel
EG 6218	603	Emergency	Diesel
EG 6312	603	Emergency	Diesel
EG 6289	603	Emergency	Diesel
EG 6290	603	Emergency	Diesel
EG 6472	170	Emergency	Diesel
EG 5886	363	Emergency	Diesel
EG 6031	340	Emergency	Diesel
EG 6522	330	Emergency	Diesel

	CO		NO_X		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
6192	3.32	0.83	14.5	3.62	0.42	0.11	2.44	0.61	0.39	0.10
6217	3.32	0.83	14.5	3.62	0.42	0.11	2.44	0.61	0.39	0.10
6218	3.32	0.83	14.5	3.62	0.42	0.11	2.44	0.61	0.39	0.10
6312	3.32	0.83	14.5	3.62	0.42	0.11	2.44	0.61	0.39	0.10
6289	3.32	0.83	14.5	3.62	0.42	0.11	2.44	0.61	0.39	0.10
6290	3.32	0.83	14.5	3.62	0.42	0.11	2.44	0.61	0.39	0.10
6472	1.14	0.28	5.27	1.34	0.37	0.09	0.35	0.09	3.74	0.93
5886	2.43	0.61	11.26	2.86	0.80	0.20	0.74	0.19	7.99	1.99
6031	1.94	0.49	8.99	2.28	0.64	0.16	0.59	0.15	6.38	1.59
6522	2.20	0.55	10.24	2.60	0.73	0.18	0.68	0.17	7.26	1.81
Totals	**27.63**	**6.91**	**122.76**	**30.8**	**5.06**	**1.29**	**17**	**4.26**	**27.71**	**6.92**

EUG 41. Emergency Engine Subject to NSPS Subpart JJJJ

Point ID#	Capacity (hp)	Make/Model	Installed Date
GE6500	23	Generac 58851	2013

Emissions factors for NOx, CO, and VOC are NSPS Subpart JJJJ limits. Emissions of PM and SO_2 are taken from AP-42 (7/00), Section 3.2. Since PM is from natural gas combustion, $PM_{2.5}$ is assumed equal to PM. 100 hours per year operations were used.

Rated Horsepower	Pollutant	Emission Factor	Emissions	
			lb/hr	**TPY**
23-hp (0.26 MMBTUH)	NOx	11.3 g/kw-hr	0.40	0.02
	CO	610 g/kW-hr	22.8	1.10
	VOC	0.56 g/kw-hr	0.02	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01
	PM_{10} / $PM_{2.5}$	0.05 lb/MMBTU	0.01	0.01

FACILITY-WIDE PTE ESTIMATE TOTALS

EMISSION UNITS	CO		NOx		PM_{10}		SOx		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
EUG 1	56.52	248.6	123.1	539.2	5.00	21.95	19.76	86.56	3.62	16.04
EUG1A	3.8	16.5	4.5	19.6	0.34	1.49	1.16	1.92	0.25	1.08
EUG 2	37.8	166	90.0	394	3.36	14.7	11.70	51.24	2.49	10.9
EUG 2A	18.1	79.10	12.88	39.00	1.63	7.16	5.59	9.23	1.18	5.18
EUG 3	8.24	36.1	9.81	42.98	0.75	3.27	1.70	7.43	0.54	2.36
EUG 3A	2.87	12.55	3.41	14.94	0.26	1.14	0.90	3.96	0.19	0.82
EUG 4	2.71	11.8	3.22	14.10	0.25	1.07	0.84	1.38	0.18	0.78
EUG 5	5.04	22.1	6.00	26.3	0.46	2.00	5.85	25.63	0.33	1.45
EUG 6	6.80	29.8	8.10	35.5	0.62	2.70	2.11	9.24	0.45	1.95
EUG 7, 8, 9	0	0	0	0	0	0	0	0	53.7	235
EUG 11	0.12	0.51	0.04	0.19	0	0	0.12	0.51	0.04	0.19
EUG 11a	3.7	16.4	0.7	3.02	0	0	1.74	7.66	8.5	37.3
EUG 12	0	0	0	0	0	0	0	0	35	153
EUG 14 (1)	0	0	0	0	0	0	0	0	0	0
EUG 18	0	0	0	0	0	0	0	0	6.31	27.6
EUG 19	0	0	0	0	0	0	0	0	11.6	50.8
EUG 20	0	0	0	0	0	0	0	0	3.55	14.04
EUG 21	0	0	0	0	0	0	0	0	1.62	7.09
EUG 22 (2)	0	0	0	0	0	0	0	0	0	0
EUG 23	0	0	0	0	0	0	0	0	0.67	9.77
EUG 24	0	0	0	0	0	0	0	0	1.01	4.47
EUG 25	0	0	0	0	0	0	0	0	1.52	6.64
EUG 27 (2)	0	0	0	0	0	0	0	0	0	0
EUG 28	0	0	0	0	0	0	0	0	3.30	14.3
EUG 29-31 (3)	0	0	0	0	0	0	0	0	0	0
EUG 32	0	0	0	0	0.20	0.90	0	0	1.46	6.40
EUG 33, 34	0	0	0	0	0.04	0.17	0	0	0.7	3.0
EUG 35	0	0	0	0	0	0	0	0	0.14	0.58
EUG 36	23.31	71.97	13.80	42.75	0.12	0.38	0.01	0.01	0.19	0.57
EUG 37	25.7	113	26.0	114	2.33	10.2	7.82	34.22	1.69	7.38
EUG 38	27.63	6.91	122.8	30.8	5.06	1.29	17.00	4.26	27.71	6.92
EUG 39	3.04	13.32	2.28	9.99	0.58	2.53	1.98	3.26	0.38	1.66
EUG 40	5.00	21.90	3.75	16.42	0.95	4.16	3.25	5.37	0.62	2.74
EUG-41	22.8	1.1	0.40	0.02	0.01	0.01	0.01	0.01	0.02	0.01
Totals	**253.18**	**867.66**	**430.79**	**1342.81**	**21.96**	**75.12**	**81.54**	**251.89**	**168.96**	**630.02**

(1) EUG 14 is reported in heater and flare emissions.
(2) Unit currently out of service.
(3) Pressure vessels with only fugitive VOC emissions.

The facility is a major source of greenhouse gas (GHG) emissions with emissions greater than 100,000 TPY. The facility is also a major source of Hazardous Air Pollutants (HAPs).

NET EMISSIONS CHANGES

The initial step in the process of determining net emissions changes was summing the post-project potential emissions for each new unit, each modified unit, and each unit with increased utilization. These totals exceeded the PSD levels of significance for NO_x, CO, VOC and SO_2, $PM_{2.5}/PM_{10}$, and GHG, requiring determination of net emissions changes.

Net emissions changes for the project were calculated by using the post-project potential emissions for each new unit, each modified unit, and each unit with increased utilization compared to the Baseline Actual Emissions (BAE) for each. The Projected Actual Emissions (PAE) for each new, modified, and increased-utilization unit were taken as PTE, except for SO_2. To remain under the 40 TPY SER for SO_2, the PAE for the SRUs will be based on 100 ppmv SO_2 and the PAE for the FCCU regenerator will be based upon 10 ppmv SO_2. (Reported actual SO_2 emissions have been well below these projected values.)

The BAE period for all pollutants was calendar years 2010 and 2011.

There were several contemporaneous projects:

- Numerous pipelines were constructed between the two refineries as part of the "integration" project.
- The DHTU at East Refinery was revamped to meet new diesel fuel sulfur standards.
- The CCR at East Refinery was upgraded to a higher throughput.
- Boilers 3 and 4 have been shut down.
- Boiler 10 was installed under a PSD permit; as a unit operating less than 2 years, BAE is equal to PAE, for a net change of zero in this latest expansion.
- Sulfur reduction projects: flare gas recovery at the West Refinery, NaSH/Amine Unit at the East Refinery, and sour gas fuel line interconnection; the BAE for fuel gas combustion units at the West Refinery uses NSPS Subpart J limits as required by Consent Decree.
- Coker blowdown project.
- "Benzap" (Mobile Source Air Toxics) Unit at East Refinery, which has now been repurposed as the Naphtha Splitter Reboiler.
- Loading Terminal vapor combustion unit at HEP.
- Numerous older, grandfathered tanks have been replaced with newer tanks, mostly with floating roofs; despite the throughput increase, VOC emissions from tanks will decline from the BAE.

Baseline Actual Emissions

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
East Refinery								
DHTU Charge Heater 1H-101	6156	3.29	12.9	0.84	1.16	1.16	0.20	20,414
CCR Charge Heater 10H-101	6163	24.5	19.7	1.29	1.78	1.78	0.30	31,251
CCR #2-1 Interheater 10H-102	6163	12.8	10.4	0.68	0.94	0.94	0.16	16,428
CCR #2-1 Interheater 10H-103	6163	6.31	5.11	0.33	0.46	0.46	0.08	8,103
CCR Stabilizer Reboiler 10H-104	6162	3.30	0.09	0.51	0.70	0.70	0.12	12,236
Naphtha Splitter Reboiler 10H-105	6162	0.32	0.67	0.044	0.06	0.06	0.027	1,059
CCR Interheater #1 10H-113	39225	14.7	31.0	2.03	2.80	2.80	0.48	49,103
Boiler #1	6150	3.61	39.1	2.56	3.53	3.53	0.59	62,043
Boiler #2	6150	5.10	42.1	2.75	3.80	3.80	0.62	66,720
Boiler #3	6151	2.34	40.5	2.65	3.66	3.66	0.62	64,305
Boiler #4	6151	4.88	37.4	2.45	3.38	3.38	0.55	59,303
Sulfur Recovery Unit / Tail Gas Treating Unit #1	6152	0.36	37.2	0.014	0.02	0.02	0.90	345
Sulfur Recovery Unit / Tail Gas Treating Unit #2	36200	3.00	1.80	0.12	0.16	0.16	0.19	2,852
NHDS Charge Heater 02H-001	36195	3.46	0.04	0.42	0.58	0.58	0.10	10,259
NHDS Stripper Reboiler 02H-002	36198	2.84	0.38	0.37	0.52	0.52	0.09	9,063
CDU Atmospheric Tower Heater	6155	84.4	57.9	3.79	5.24	5.24	1.30	91,888
CDU Vacuum Tower Heater	6155	41.6	28.5	1.87	2.58	2.58	0.64	45,258
FCCU Charge Heater B-2	6158	33.3	18.3	1.20	1.65	1.65	0.31	20,414
FCCU Regenerator	6153	3.08	75.1	0.094	30.2	30.2	9.17	158,360
Unifiner Charge Heater H-1	6167	7.31	6.02	0.39	0.54	0.54	0.091	9,554
Scanfiner Charge Heater 12H-101	23133	1.20	0.01	0.092	0.13	0.13	0.023	2,234
Tanks	Multiple	-	-	3.19	-	-	-	62
Equipment Leaks	---	-	-	204.3	0.27	0.027	-	267
Wastewater Treatment	13409	-	-	240.0	-	-	-	-
HEP (Loading Terminal)								-
Tanks	Multiple	-	-	156.5	-	-	-	62
Loading/Unloading Racks (excluding Terminal)	---	-	-	3.62	-	-	-	-
Loading Terminal	6275	14.83	37.10	37.5	1.48	1.48	0.39	9,214
Equipment Leaks	N/A	-	-	2.56	0.27	0.027	-	267

Baseline Actual Emissions - Continued

Unit	Point ID	NOx TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
West Refinery								
#7 Boiler	#7 Boiler	46.9	20.3	1.33	1.84	1.84	0.01	32,261
#8 Boiler	#8 Boiler	69.0	29.9	1.96	2.71	2.71	0.01	47,469
#9 Boiler	#9 Boiler	53.4	31.4	2.06	2.84	2.84	0.01	49,843
#10 Boiler	#10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	122,776
CDU Atmospheric Tower Heater	CDU H-1	112	85.1	5.57	7.70	7.70	30.9	135,020
CDU #1 Vacuum Tower Heater	CDU H-2	30.6	25.2	1.65	2.28	2.28	46.7	39,951
CDU #2 Vacuum Tower Heater	CDU H-3	8.97	7.39	0.48	0.67	0.67	2.7	11,723
Unifiner Charge Heater	Unifiner H-2	9.03	4.96	0.32	0.45	0.45	1.69	7,867
Unifiner Stripper Reboiler	Unifiner H-3	13.2	7.24	0.47	0.66	0.66	2.46	11,491
No. 2 Platformer Charge Heater	#2 Plat PH-3	8.20	4.50	0.29	0.41	0.41	1.53	7,138
No. 2 Platformer Charge Heater	#2 Plat PH-4	9.93	5.45	0.36	0.49	0.49	0.68	8,649
Coker Drum Charge Heater	Coker B-1	11.6	10.6	0.70	0.96	0.96	0.01	16,887
Coker Pre-Heater	Coker H-3	5.31	4.86	0.32	0.44	0.44	0.004	7,708
LEU Raffinate Mix Heater	LEU H101	7.31	4.01	0.26	0.36	0.36	1.68	6,363
LEU Extract Mix Heater	LEU H-102	32.6	29.8	1.95	2.70	2.70	167	47,303
LEU Hydrotreater Charge Heater	LEU H-201	9.16	5.03	0.33	0.45	0.45	2.10	7,977
MEK – Wax Free Oil Heater	MEK H-101	36.3	19.9	1.30	1.80	1.80	0.01	31,595
MEK – Soft Wax Heater	MEK H-2	13.1	9.00	0.59	0.81	0.81	3.40	14,282
Loading / Unloading Racks	Multiple	-	-	6.40	0.90	0.11	-	-
Tanks	Multiple	-	-	78.3	-	-	-	72.7
Equipment Leaks	---	-	-	168.1	1.68	0.11	-	198
Wastewater Treatment	15943	-	-	196.3	-	-	-	-
TOTAL BASELINE ACTUAL EMISSIONS		**791.9**	**883.4**	**1146.3**	**103.06**	**100.21**	**287.1**	**1,357,638**

Post-Project Potential To Emit For NO_X, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG / SO_2 Projected Actual Emissions

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
East Refinery								
CCR Helper Heater	N/A	3.29	4.38	0.59	0.82	0.82	1.07	17,880
NHDS Helper Heater	N/A	1.31	1.75	0.24	0.33	0.33	0.43	7,152
DHTU Helper Heater	N/A	6.57	8.76	1.18	1.63	1.63	2.14	35,761
ROSE Heater	N/A	5.52	7.36	0.99	1.37	1.37	1.80	30,039
New Tanks	Multiple	-	-	1.03	-	-	-	24.9
Equipment Leaks – New Units	Multiple	-	-	26.4	-	-	-	347.5
DHTU Charge Heater 1H-101	6156	17.52	28.9	1.89	2.61	2.61	1.43	57,217
CCR Charge Heater 10H-101	6163	26.3	43.3	2.83	3.92	3.92	2.14	85,825
CCR #2-1 Interheater 10H-102	6163	66.4	36.4	2.39	3.30	3.30	1.8	72,236
CCR #2-1 Interheater 10H-103	6163	16.4	9.02	0.59	0.82	0.82	0.45	17,880
CCR Stabilizer Reboiler 10H-104	6162	18.6	30.7	2.01	2.77	2.77	1.51	60,793
Naphtha Splitter Reboiler 10H-105	6162	13.1	17.5	2.36	3.26	3.26	1.78	71,521
CCR Interheater #1 10H-113	39225	33.9	55.9	3.66	5.06	5.06	2.76	110,858
Boiler #1	6150	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #2	6150	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #3	6151	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #4	6151	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Sulfur Recovery Unit / Tail Gas Treating Unit #1	6152	4.91	99.0	0.13	0.18	0.18	14.0	3,604
Sulfur Recovery Unit / Tail Gas Treating Unit #2	36200	10.6	24.3	0.29	0.39	0.39	9.84	7,787
NHDS Charge Heater 02H-001	36195	8.54	14.1	0.92	1.27	1.27	0.69	27,893
NHDS Stripper Reboiler 02H-002	36198	9.68	15.9	1.04	1.44	1.44	0.79	31,612
CDU Atmospheric Tower Heater	6155	84.4	57.9	5.86	8.09	8.09	4.42	177,372
CDU Vacuum Tower Heater	6155	52.6	36.1	2.36	3.26	3.26	1.78	71,521
FCCU Charge Heater B-2	6158	108	59.5	3.90	5.38	5.38	2.94	118,010
FCCU Regenerator	6153	33.2	505	0.094	74.5	74.5	23.1	293,591
Unifiner Charge Heater H-1	6167	18.4	15.1	0.99	1.37	1.37	0.75	30,039
Scanfiner Charge Heater 12H-101	23133	7.73	9.09	0.60	0.82	0.82	0.45	18,023
Existing Tanks	Multiple	-	-	3.19	-	-	-	80.5
Existing Equipment Leaks (incl. mod. units)	---	-	-	212.1	0.27	0.027	-	334
Wastewater Treatment	13409	-	-	220.0	-	-	-	-

*NOTE: Since PAE cannot be less than BAE, higher emission rates are being shown for this unit's PAE. Permit emission limits are lower than PAE.

Post-Project Potential To Emit For NO_X, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG / SO_2 Projected Actual Emissions - Continued

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
West Refinery								
PDA/ROSE Heater	N/A	10.0	13.3	1.79	2.48	2.48	3.25	54,356
Hydrogen Plant Reformer Heater	---	16.4	21.9	2.95	4.08	4.08	5.34	89,401
Hydrogen Plant Process Emissions	---	-	4.06	-	-	-	-	75,991
New Tanks	---	-	-	22.1	-	-	-	24.9
Equipment Leaks – New Units	---	-	-	6.28	-	-	-	258
#7 Boiler	#7 Boiler	125	54.1	3.54	4.90	4.90	2.67	107,282
#8 Boiler	#8 Boiler	125	54.1	3.54	4.90	4.90	2.67	107,282
#9 Boiler	#9 Boiler	92	54.1	3.54	4.90	4.90	2.67	107,282
#10 Boiler	#10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	153,484
CDU Atmospheric Tower Heater	CDU H-1	151	115	7.56	10.4	10.4	30.9	228,868
CDU #1 Vacuum Tower Heater	CDU H-2	35.0	28.9	1.89	2.61	2.61	46.7	57,217
CDU #2 Vacuum Tower Heater	CDU H-3	18.9	15.6	1.02	1.41	1.41	2.68	30,897
Unifiner Charge Heater	Unifiner H-2	24.1	13.2	0.87	1.20	1.20	1.69	26,248
Unifiner Stripper Reboiler	Unifiner H-3	39.1	21.5	1.41	1.94	1.94	2.46	42,555
No. 2 Platformer Charge Heater	#2 Plat PH-3	23.8	13.1	0.86	1.18	1.18	1.53	25,962
No. 2 Platformer Charge Heater	#2 Plat PH-4	19.6	16.2	1.06	1.46	1.46	1.91	32,041
Coker Drum Charge Heater	Coker B-1	23.7	21.6	1.42	1.96	1.96	1.07	42,913
Coker Pre-Heater	Coker H-3	12.7	11.6	0.76	1.05	1.05	0.57	23,030
LEU Raffinate Mix Heater	LEU H101	14.7	8.08	0.53	0.73	0.73	1.68	16,021
LEU Extract Mix Heater	LEU H-102	59.1	54.1	3.54	4.90	4.90	167	107,282
LEU Hydrotreater Charge Heater	LEU H-201	14.7	8.08	0.53	0.73	0.73	2.10	16,021
MEK – Wax Free Oil Heater	MEK H-101	53.2	29.2	1.91	2.64	2.64	1.44	57,932
MEK – Soft Wax Heater	MEK H-2	25.8	17.7	1.16	1.60	1.60	3.40	35,045
Loading / Unloading Racks	Multiple	-	-	6.45	0.90	0.11	-	-
Existing Tanks	Multiple	-	-	78.3	-	-	-	94.5
Existing Equipment Leaks (incl. modified units)	---	-	-	170.0	1.68	0.11	-	248
Wastewater Treatment	15943	-	-	176.3	-	-	-	-

Post-Project Potential To Emit For NO_X, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG / SO_2 Projected Actual Emissions - Continued

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
HEP (Loading Terminal)								
New Tanks	Multiple	-	-	23.2	-	-	-	24.9
Equipment Leaks - New Units	16	-	-	7.09	-	-	-	348
Loading/Unloading Racks (excluding Terminal)	---	-	-	3.62	-	-	-	-
Existing Tanks	Multiple	-	-	156.5	-	-	-	29.0
Vapor Combustion Unit	6275	14.8	37.1	37.5	1.48	1.48	0.39	11,518
Existing Equipment Leaks (incl. modified units)	16	-	-	2.56	0.27	0.027	-	347.5
TOTAL POST-PROJECT EMISSIONS		**1,607.1**	**2,106.9**	**1,254.5**	**219.7**	**216.9**	**384.1**	**3,463,979**

Project Emissions Changes

Pollutant	PAE TPY	BAE TPY	Difference TPY	PSD Levels of Significance, TPY	Netting Required?
NO_x	1607.7	791.9	815.8	40	Yes
CO	2106.9	883.4	1223.5	100	Yes
VOC	1254.5	1146.3	108.2	40	Yes
PM_{10}	219.7	103.0	116.7	15	Yes
$PM_{2.5}$	216.8	100.2	116.7	10	Yes
SO_2	384.1	287.1	97.0	40	Yes
GHG	3,463,979	1,357,638	2,106,341	75,000	Yes

PSD Netting

Project	NOx TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
Projected Actual Emissions	1607.7	2106.9	1254.5	219.66	216.81	384.1	3,463,979
Baseline Actual Emissions	-792.14	-883.36	-1,146.27	-103.06	-100.21	-286.98	-1,357,638
East CDU Atmospheric Tower Heater	-51.8	-14.5	--	--	--	--	--
East Removed Tanks	--	--	-0.79	--	--	--	-62
HEP Removed Tanks	--	--	-38.8	--	--	--	--
HEP Removed Thermal Oxidizer	-2.47	-6.18	-8.00	-0.56	-0.56	--	--
HEP Added Tanks	--	--	8.33	--	--	--	10.4
Vapor Combustor	14.8	37.1	37.45	1.48	1.48	0.39	9,214
West Removed Tanks	--	--	-57.4	--	--	--	-72.7
West Heaters – Subpart J to Subpart Ja Fuel	--	--	--	--	--	-42.79	--
West Boilers 3 and 4 Removed	-196	-57.7	-3.78	-5.22	-5.22	-20.7	-91,495
West PDA Propane Compressor Electrified	-0.86	-3.44	-1.00	-0.17	-0.17	-0.01	-1,089
West Unifiner H2 Recycle Compressor Electrified	-0.35	-4.62	-1.34	-0.23	-0.23	-0.01	-1,462
West Plat PH-1/2 Heater Removed	-31.5	-17.3	-1.13	-1.56	-1.56	-5.89	-27,415
West Plat PH-5 Heater Removed	-17.4	-11.3	-0.74	-1.02	-1.02	-0.01	-17,861
West Plat PH-6 Heater Removed	-7.69	-4.81	-0.32	-0.44	-0.44	-<0.01	-7,632
West Plat PH-7 Heater Removed	-3.65	-2.00	-0.13	-0.18	-0.18	-0.68	-3,177
West #2 Cooling Tower Circulating Pump Electrified	-0.74	-2.94	-0.85	-0.15	-0.15	-<0.01	-189
West #3 Cooling Tower Circulating Pump Electrified	-1.78	-7.11	-2.07	-0.36	-0.36	-0.01	-19.3
West #6 Cooling Tower Spray Pump Electrified	-2.04	-8.14	-2.37	-0.41	-0.41	-0.01	--
West #6 Cooling Tower Circulating Pump Electrified	-0.83	-3.32	-0.97	-0.17	-0.17	--	-42.5
West #3 Cooling Tower Replacement	--	--	-3.68	-5.12	-0.03	--	--
	--	--	3.68	3.30	0.02	--	--
West #10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	122,788
NET EMISSIONS CHANGES	552.3	1194.7	39.3	112.79	114.60	36.5	2,087,846
Full PSD Review Required?	**Yes**	**Yes**	**No**	**Yes**	**Yes**	**No**	**Yes**

SECTION V. TRIVIAL ACTIVITIES

ODEQ has established a list of activities in OAC 252:100 Appendix J that are considered inconsequential with regards to air emissions. Unless the activity is subject to an applicable State or Federal requirement, these activities are not specifically identified in the permit. However, the standard conditions of the permit specify that the facility is allowed to operate these activities without special conditions.

SECTION VI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified in the application and listed in OAC 252:100-8, Appendix I, are listed below. Activities at the refinery considered insignificant may change from time to time. Thus, the following list of activities may expand to include other activities considered insignificant in Appendix I of the OAC rules. Recordkeeping is required for those activities preceded by an asterisk (*) and such are listed in the Specific Conditions.

1. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTUH heat input (commercial natural gas).
2. *Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for peaking power service not exceeding 500 hours/year. EG 5414 is a 59 hp gasoline-fired emergency engine meeting the criteria for insignificant activity criteria. Emission estimates for the engine is calculated using factors for Table 3.3-1 of AP-42 (10/96), listed rated engine horsepower, and the 500-hour criterion associated with this activity.

Engine #	HP	CO		NOx		PM_{10}		SOx		VOC	
		PPH	TPY	PPH	TPY	PPH	TPY	PPH	TPY	PPH	TPY
EG 5414	59	0.41	1.81	0.65	0.16	0.04	0.01	0.03	0.01	1.30	0.33

3. Emissions from stationary internal combustion engines rated less than 50 hp output. A list shall be maintained on-site.
4. Cold degreasing operations utilizing solvents that are denser than air.
5. Torch cutting and welding of less than 200,000 tons of steel fabricated per year. All work of this nature is for maintenance and is a Trivial Activity.
6. *Non-commercial water washing operations (less than 2,250 barrels/year) and drum crushing operations of empty barrels less than or equal to 55 gallons with less than three percent by volume of residual material.
7. Hazardous waste and hazardous materials drum staging areas.
8. Hydrocarbon contaminated soil aeration pads utilized for soils excavated at the facility only.
9. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.
10. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas.

11. Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in 252:100-8-3(e)(1).
12. Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period.
13. Emissions from the operation of groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to *de minimis* limits for air toxics (252:100-41-43) and HAPS (§112(b) of CAAA90).
14. Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature.

SECTION VII. BACT REVIEW

OAC 252:100-8-31 states that BACT "*means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts or other costs, determines is achievable for such source or modification....*" A BACT analysis is required to assess the appropriate level of control for each new or physically modified emissions unit for each pollutant that exceeds the applicable PSD Significant Emissions Rate (SER).

The U.S. EPA has stated its preference for a "top-down" approach for determining BACT and that is the methodology used for this permit review. After determining whether any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the available control technologies, including the most stringent control technology, for a similar or identical source or source category. If the proposed BACT is equivalent to the most stringent emission limit, no further analysis is necessary.

If the most stringent emission limit is not selected, further analyses are required. Once the most stringent emission control technology has been identified, its technical feasibility must be determined; this leads to the reason for the term "available" in Best Available Control Technology. A technology that is available and is applicable to the source under review is considered technically feasible. A control technology is considered available if it has reached the licensing and commercial sales stage of development. In general, a control option is considered applicable if it has been, or is soon to be, developed on the same or similar source type. If the control technology is feasible, that control is considered to be BACT unless economic, energy, or environmental impacts preclude its use. This process defines the "best" term in Best Available Control Technology. If any of the control technologies are technically infeasible for the emission unit in question, that control technology is eliminated from consideration.

The remaining control technologies are then ranked by effectiveness and evaluated based on energy, environmental, and economic impacts beginning with the most stringent remaining technology. If it can be shown that this level of control should not be selected based on energy, environmental, or economic impacts, then the next most stringent level of control is evaluated. This process continues until the BACT level under consideration cannot be eliminated by any energy, environmental, or economic concerns.

The five basic steps of a top-down BACT review are summarized as follows:

Step 1. Identify Available Control Technologies
Step 2. Eliminate Technically Infeasible Options
Step 3. Rank Remaining Control Technologies by Control Effectiveness
Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic impacts
Step 5. Select BACT and Document the Selection as BACT

In Step 1 in a "top down" analysis, all available control options for the emission unit in question are identified. Identifying all potential available control options consists of those air pollution control technologies or control techniques with a practical potential for application to the emission unit and the regulated pollutant being evaluated.

In Step 2, the technical feasibility of the control options identified in Step 1 are evaluated and the control options that are determined to be technically infeasible are eliminated. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option on the emission unit under review due to technical difficulties. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 of the "top-down" analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information. Once the control effectiveness is established in Step 3 for all feasible control technologies identified in Step 2, additional evaluations of each technology, based on energy, environmental, and economic impacts, are considered to make a BACT determination in Step 4. The energy impact of each evaluated control technology is the energy benefit or penalty resulting from the operation of the control technology at the source. The costs of the energy impacts either in additional fuel costs or the cost of lost power generation impacts the cost-effectiveness of the control technology.

The second evaluation to be reviewed for each control technology remaining in Step 4 is the environmental evaluation. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology. The third evaluation addresses the economic evaluation of the remaining control technologies. The cost to purchase and to operate the control technology is analyzed. The capitol and annual operating costs are estimated based on established design parameters or documented assumptions in the absence of established designed parameters. The cost-effectiveness describes the potential to achieve the required emission reduction in the most economical way. It also compares the potential technologies on an economic basis.

In Step 5, BACT is selected for the pollutant and emission unit under review. BACT is the highest ranked control technology not eliminated in Step 4. The U.S. EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those that provide the maximum degree of emission reduction. Second, any decision to require a lesser degree of emission reduction must be justified by an objective analysis of energy, environmental, and economic impacts. As stated in the BACT definition, in no case can the maximum available emission rate for the sources exceed the New Source Performance Standard (NSPS) emission rate for the source, or cause an exceedance of the National Ambient Air Quality Standards (NAAQS). Therefore, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate below those specified by the NSPS and the ambient impact cannot exceed the NAAQS. The new or modified emission sources for this project that are subject to BACT are new process heaters, and new components that will be installed for new or modified process units.

Potentially applicable emission control technologies were identified by researching PSD permits recently issued by ODEQ for the ConocoPhillips Ponca City Refinery and other refineries, the U.S. EPA control technology database, technical literature, control equipment vendor information, and by using process knowledge and engineering experience. Manufacturers were contacted to provide information regarding emission guarantees. The RACT/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies that have been approved in PSD permits as BACT for numerous types of process units. Process units in the database are grouped into categories by industry. Additional sources of potentially applicable emission control technologies include the California Air Resource Board (CARB) BACT determinations database. These sources were reviewed in order to supplement ODEQ permit review, vendor information, and RBLC search results.

Technical literature and guidance documents consulted for the BACT evaluations include:

- New Source Review Workshop Review Manual (Draft, October 1990);
- EPA's "Alternate Control Techniques Document for NOX Emissions" (June 1994);
- EPA's Air Pollution Technology Fact Sheets (2003);
- Emission Estimation Protocol for Petroleum Refineries, Version 2.1.1 (May 2011);
- EPA's Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources (AP-42, January 1995);
- PSD and Title V Guidance for Interim Permitting Guidance for Greenhouse Gases (March 2011); and
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Industry (October 2010).

RBLC categorizes heaters as smaller than 100 MMBTUH and smaller than 250 MMBTUH. The new heaters are all smaller than 100 MMBTUH except for the hydrogen plant heater (125 MMBTUH) which is in the category of smaller than 250 MMBTUH. While there are numerous determinations listed for hydrogen plants, only three are smaller than 250 MMBTUH.

A. New Process Heaters

1. NOx BACT Review

NOx emissions are generated from the high temperature dissociation of atmospheric nitrogen molecules and their subsequent reaction with oxygen to form nitrogen oxide (NO) or nitrogen dioxide (NO_2) (thermal NOx) and from chemically bound nitrogen in the fuel (fuel NOx). Thermal NOx is primarily formed at temperatures above 2,400°F; therefore, limiting the temperature of the flame can control its generation. Fuel NOx is formed when the fuel nitrogen is converted to hydrogen cyanide and then oxidized to form NO that further oxidizes in the atmosphere to NO_2. Since the first step of the oxidation occurs in the combustion chamber, providing an oxygen-deficient atmosphere in the combustion chamber can significantly reduce NO, and thereby NO_2 formation. Some combustion processes can be modified to minimize NOx emissions by reducing peak flame temperature, gas residence time in the flame zone, and oxygen concentration in the flame zone.

Step 1. Identify Available Control Technologies
A variety of technologies and techniques exist for control of NOx emissions from process heaters, which have the primary purpose of transferring heat to a process through exchangers. These include add-on control devices, and techniques to minimize NOx formation. The following is a list of equipment and add-on control technologies that were identified for controlling NOx emissions from process heaters and boilers.

- Low-NOx burners (LNB);
- Ultra Low-NOx Burners (ULNB);
- Flue Gas Recirculation (FGR);
- Selective Non-Catalytic Reduction (SNCR);
- Non-Selective Catalytic Reduction (NSCR);
- Selective Catalytic Reduction (SCR); and
- EMX™/SCONOX.

These technologies can be used alone or in combination, along with good combustion practices, to minimize NOx emissions. For example, lower emitting burners can be combined with add-on controls or combustion techniques, such as ULNB with SCR or SNCR, LNB with SCR or SNCR, and LNB with FGR.

Step 2. Eliminate Technically Infeasible Options
The Step 1 technologies were reviewed to determine which are technically feasible, to eliminate technically infeasible options. Some options have significant limitations in refining applications as compared to other technologies that render them infeasible and remove them from further consideration. These include EMX/SCONOX, NSCR, and FGR.

EMX™/SCONOX

The EMX™ catalyst is the latest generation of SCONOX technology. EMX™ is a multi-pollutant catalyst that does not require ammonia. While this technology has been demonstrated on units firing pipeline quality natural gas, there is no practical experience with operating on flue gas streams from refinery gas-fired equipment. At this time, EMX™ is not being used in any commercial refinery situation with equipment using a sulfur-bearing fuel gas stream such as refinery fuel gas because SO_2 will contaminate the catalyst and reduce efficiency over time. Additionally, the mechanical complexity of EMX™ increases in rough proportion to the heat duty rating of the unit. For larger commercial scale units, a large number of mechanical dampers must operate reliably every several minutes under hot and corrosive conditions to divert the flow of flue gas and regenerating hydrogen gas through segments of the catalyst beds. The challenge presented by this demanding design feature is aggravated by the fact that refinery fuel gas combustion products have a higher potential corrosive acid concentration than natural gas combustion products.

The specified EMX™ catalyst operating temperature range of 300 to 700°F is also a practical limitation for use with refinery process heaters. The typical exhaust temperature range is significantly higher for refinery process heaters and boilers. The EMX™ catalyst technology is not usable unless the tolerated temperature range is increased or the exhaust temperature of the heaters is controlled.

EMX™ also creates an increase in system pressure drop that results in a substantial operating cost penalty. It is estimated that the net power incremental requirement due to higher catalyst bed pressure drop is about 1.8 times that associated with a comparable SCR system.

Because of the lack of commercial refinery experience, the catalyst's sensitivity to sulfur compounds, and mechanical limitations, EMX™ is deemed to be technically infeasible for the refinery process heaters.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a flue gas treatment technology that is similar to the catalytic controls on modern automobiles. Precious metal catalysts, such as platinum, are used to promote reactions that reduce most nitrogen oxides (NO) in the exhaust gases to molecular nitrogen (N_2). Likewise, the catalyst will simultaneously convert over 98% of the NOx and CO and most of the unburned HC emissions according to the NSCR [unbalanced] reactions below:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2$$
$$NOx + CO \rightarrow CO_2 + N_2$$
$$H_2 + O_2 \rightarrow H_2O$$
$$HC + \frac{1}{2} O_2 \rightarrow H_2O + CO_2$$
$$NOx + H_2 \rightarrow H_2O + N_2$$

These reactions can only occur in this manner when the oxygen content of the exhaust is controlled to less than 1% vol. (typically about 0.5% vol.), which is accomplished by attaching an air/fuel controller (lambda sensor) to maintain the chemically correct (or stoichiometric) air/fuel ratio (AFR), such that all the fuel and oxygen in the mixture are consumed on combustion, and is typically referred to as a rich-burn or stoichiometric operation. The formulas above show that CO must be present in the exhaust gas in order for the NOx to be reduced to N_2. The refinery heaters operate in a lean burn (i.e., oxygen rich) environment where the O_2 content is substantially greater than 1% vol. There would not be enough CO present in the exhaust stream to effectively react the NOx to N_2. In addition, oxygen will adsorb on the catalyst and block the reaction. Therefore, NSCR is deemed technically infeasible for the refinery heaters and boilers.

FGR

Flue gas recirculation (recovery) involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculation of the hot O_2-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner wind box. Flue gas recirculation has not been demonstrated to function efficiently on process heaters that are subject to highly variable loads and that burn fuels with variable heat value. There are significant technical differences between the proposed process heaters and those combustion sources where flue gas recirculation has been demonstrated in practice. Thus, FGR has been eliminated as BACT for NOx reduction for the new process heaters proposed by HFTR.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The remaining options are ranked based on effectiveness.

Technology	Control Efficiency %
ULNB + SCR	85-99
LNB + SCR	80-99
ULNB + SNCR	75-95
LNB + SNCR	50-99
LNB	<40
ULNB	70-90
SCR	70-90
SNCR	30-50
LNB	<40
No control	---

Step 4. Evaluate Remaining Options

The remaining top-ranked technologies are evaluated in this section, including their effectiveness, and any energy, environmental, and economic impacts.

LNB

The use of LNB is often considered as a baseline NOx control technology, since most heaters and boilers in the refining industry are capable of being equipped with LNB. LNB technology uses advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. The two types of LNB include staged fuel and staged air burners. Staged fuel burners are particularly useful for NOx reduction in refinery process heaters. The burners separate the combustion zone into two regions, with lower combustion temperature in the first zone that reduces overall oxygen, with fuel injected into the second zone to reduce overall formation of thermal NOx. A NOx emission rate of 0.08 lb/MMBTU is typically considered an average emission rate for LNB technology. As a stand-alone control technology for a new heater, ULNB would be considered more effective for NOx emission control. However, LNB can be considered in conjunction with other add-on controls.

ULNB

There are several designs of ULNB currently available. These burners combine two NOx reduction steps into one burner; typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment. In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. Thus the average oxygen concentration is reduced in the flame without reducing the flame temperatures below that which is necessary for optimal combustion efficiency. This design is predominately used with liquid fuels. Modern ULNB technology is available at a NOx emission rate of 0.03 lb/MMBTU for the size range of new process heaters proposed for the project.

SCR alone or SCR with ULNB or LNB

SCR is a post-combustion NOx control technology. In SCR, ammonia (NH_3) diluted with air or steam is injected into the flue gas upstream of a catalytic reactor. On the catalyst surface, the NH_3 reacts with NOx to form molecular nitrogen and water.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

The SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The SCR system requires ammonia in the presence of a catalyst. The presence of the catalyst effectively reduces the ideal reaction temperature for NOx reduction to between 475 and 850°F and increases the surface area available for NOx reduction. As a postcombustion process, the SCR system is usually installed to receive flue gas after it has left the combustion chamber. The exact location of the SCR reactor will vary depending upon what other type of pollution control systems are also present. Therefore, the applicability of SCR is limited to heaters that have both a flue gas temperature appropriate for catalytic reaction and space for the catalyst bed large enough to provide sufficient residence time for the reaction to occur. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NOx concentration, the exhaust temperature, the ammonia injection rate, the type of catalyst, and the presence of catalyst poisons, such as particulate matter and SO_2.

The EPA report "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic compounds at Tier 2/Gasoline Sulfur Refinery Projects" (John Seitz, January 19, 2001) served as the basis for SCR cost effectiveness calculations. The complete report, including economic analyses, is available at www.epa.gov/region7/air/nsr/nsrmemos/t2bact.pdf. The EPA report analyzed four burner sizes (10, 50, 75, and 150 MMBTUH) which are comparable to heaters proposed in this application. 90% NOx control was evaluated. Costs were then increased by the consumer price index relative to 2001, a factor of 1.336. The costs, $/ton, decrease as unit size increases, but all costs exceeded $10,000 per ton. It is agreed that these costs are excessive and SCR may be rejected.

Burner Size	**Costs of SCR ($/ton) 2014 $**
10	43,920
50	15,333
75	12,641
150	10,369

Catalyst systems promote partial oxidation of hydrogen sulfide to sulfur dioxide which combines with water to form sulfur trioxide and sulfuric acid (H_2SO_4). SCR units typically achieve 70 to 90% NOx reduction with an ammonia exhaust concentration (ammonia slip) of 5 to 10 parts per million by volume on a dry basis (ppmvd) at 15% oxygen. Additional environmental concerns are caused by the formation of secondary particulate from the ammonia reagent. The phenomenon can be more pronounced as ammonia injection rates must be increased and ammonia slip increases as the catalyst deactivates over time. There are also safety issues with the transportation, handling and storage of ammonia. Ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). SCR can be used in combination with ULNB or LNB to increase overall NOx control efficiency to greater than 90%. While use of SCR can marginally increase NOx control effectiveness over LNB or ULNB technology, SCR has significant technical, economic, energy and environmental impacts, and thus, has been eliminated from consideration.

SNCR alone or SCNR with ULNB or LNB

SNCR describes a process by which NOx is reduced to molecular nitrogen (N_2) by injecting an ammonia or urea ($CO(NH_2)_2$) spray into the post-combustion area of the unit. Typically, injection nozzles are located in the upper area of the furnace and convective passes. Once injected, the urea or ammonia decomposes into NH_3 or NH_2 free radicals, reacts with NOx molecules, and reduces to nitrogen and water. These reactions are endothermic and use the heat of the burners as energy to drive the reduction reaction. The ammonia and urea reduction equations are shown following.

For ammonia: $4\ NO + 4\ NH_3 + O_2 \rightarrow 4N_2 + 6\ H_2O$
$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$
For urea: $4NO + 2\ CO(NH_2)_2 + O_2 \rightarrow 4N_2 + 2CO_2 + 4\ H_2O$

Both ammonia and urea have been successfully employed as reagents in SNCR systems and have certain advantages and disadvantages. Ammonia is less expensive than urea and results in substantially less operating costs at comparable levels of effectiveness. Urea, however, is able to penetrate further into flue gas streams, making it more effective in larger scale burners and combustion units with high exhaust flow rates. In addition, ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). SNCR is considered a selective chemical process because, under a specific temperature range, the reduction reactions described above are favored over reactions with other flue gas components. Although other operating parameters such as residence time and oxygen availability can significantly affect performance, temperature remains one of the most prominent factors affecting SNCR performance.

The EPA report "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects" (John Seitz, January 19, 2001) served as the basis for SNCR cost-effectiveness calculations. SNCR was considered by EPA in the draft version of this report (issued for public comment March 14, 2000) and available at www.epa.gov/NSR/ttnnsr01/gen/refbact.pdf. SNCR was discarded from the final version of this report since SNCR alone was found to be inferior to ultralow NOx burner (at a higher cost) and SNCR plus ultralow NOx burner was found to be economically inferior to SCR plus ultralow NOx burner. In addition, the combination of SNCR plus ultralow NOx burner had not been demonstrated so the performance level is uncertain. For purposes of our current application the SNCR costs are taken from the March 14, 2000 draft report and updated in the same manner that SCR costs were updated for the January 19, 2001 final report (the main update being the inclusion of a 1.5% fuel penalty). The control level from these reports of 0.015 lb NOx/MMBtu for SNCR plus ultralow NOx burner has not been demonstrated, but is assumed in the cost-effectiveness calculations. Three burner sizes were analyzed for costs using the factors in the EPA report, all with excessive costs for NOx control:

Burner Size	Incremental Costs of SNCR ($/ton) 2014 $
50	25.648
75	22,589
125	19,610

The SNCR process requires the installation of reagent storage facilities, a system capable of metering and diluting the stock reagent into the appropriate solution, and an atomization/injection system at the appropriate locations in the combustion unit. The reagent solution is typically injected along the post-combustion section of the combustion unit. Injection sites around the unit must be optimized for reagent effectiveness nd must balance residence time with flue gas stream temperature. For ammonia, the optimum reaction temperature range is 1,600 to 2,000°F, while optimum urea reaction temperature ranges are marginally higher at 1,650 to 2,100°F. Although the overall chemistry is identical to that used in the SCR system, the absence of a catalyst results in several differences. The un-catalyzed reaction requires a higher reaction temperature and is not as effective. SCR can be used in combination with ULNB or LNB to increase overall NOx control efficiency to greater than 75-90%. While use of SNCR can marginally increase NOx control effectiveness over LNB or ULNB technology, and the technology is more economical than SCR with fewer energy and environmental impacts, the technology is still not considered economically cost-effective, and thus, has been eliminated from consideration.

Step 5. Select BACT and Document the Selection as BACT

The proposed heaters for this project are small (< 100 MMBTUH except for the 125 MMBTUH hydrogen plant heater) and are related to process units downstream of crude units. The following table presents a summary of selected BACT determinations for NOx emissions for similar process heaters within the last six years. The RBLC database indicates both proposed and achieved in practice emission rates of 0.025 to 0.08 lb/MMBTU for similar sized units using ULNB and LNB technology and less than 100 MMBTUH. The RBLC does contain heaters with lower emission limits (i.e., 0.0125 to 0.02 lb/MMBTU), but these heaters utilize SCR controls, are large, and are mainly in nonattainment areas. Since ULNB provides the highest remaining feasible control, BACT has been proposed as ULNB at an emission rate of 0.03 lb/MMBTU for the new process heaters. SCR and NSCR are economically infeasible and have adverse energy and environmental impacts given the size and nature of the proposed heaters. Therefore, the ULNB controls with an emission factor of 0.03 lb /MMBTU NOx (3-hour average) is selected as BACT. The selected NOx limit equals the best demonstrated NOx emission level on RBLC for small heaters and is more stringent than the lowest level shown for comparably-sized hydrogen plants.

Summary of BACT Determinations for NOx for Process Heaters, <100 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
HFTR Woods Cross Refinery, UT	n/a	DAQEIN1012 3 0041-12	July 2012	New - Reactor Charge Heater, FCCU #2 Feed Heater, Asphalt Heaters, Heater Oil Furnace	42.1, 45, 0.8, 14	Refinery fuel gas	0.04 (3-hour average)	ULNB
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12 (project cancelled)	New - BSI Heater	50	Refinery fuel gas	0.025 (3-hr average)	ULNB
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12	Existing Naphtha Splitter Heater; Hydrocracker H5 Heater; #1 HDS Heater	46.3 44.9 33.4	Refinery fuel gas	0.035 (3-hr average)	ULNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M-5) (draft)	11/17/09	CPF Heaters H-39-03 and H-39-02	68	Refinery fuel gas	0.05 (3 one-hr test average)	LNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M-5) (draft)	11/17/09	Heaters 2008-1 - 2008-9	36	Refinery fuel gas	0.03 (no preheat) or 0.04 (air preheated)(3 one-hr test average)	ULNB

Summary of BACT Determinations for NOx for Process Heaters, <100 MMBTUH - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M-5) (draft)	11/17/09	DHT Heaters 4-81, 5-81	70	Refinery fuel gas	0.08 (3 one-hr test average)	ULNB
Hunt Refinery Tuscaloosa	AL-0242	X063A X066A X067A X070A	9/28/09	Existing modified process heaters	57 49.4 34.7 98.3 69.3 78.2 60.9 254	Refinery fuel gas	0.035	ULNB
Chevron Products Company, Pascagoula Refinery	MS-0089	1280-00058	4/14/09	Lube Hydrocracker Feed Heater Ck-003; Feed Preparation Unit Vacuum Column Feed Heater Ck-004; IDW/HDF Reactor Feed Heater CK-005; IDW/HDF Vacuum Column Feed Heater CK-006	73.25 73.95 54.53 51	Refinery fuel gas	0.045 (3-hr rolling average) 0.03 (30 day average)	ULNB

Summary of BACT Determinations for NOx for Process Heaters, <100 MMBTUH - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
ConocoPhillips, Ponca City Refinery	OK-0136	2007-042-C PSD	2/09/09	NH-1 New Naphtha Splitter Reboiler, NH-3 CTU Vacuum Heater, NH-4 CTU Crude Heater, NH-5 CTU Tar Stripper Heater	131.3, 45, 125, 98	Refinery fuel Gas	0.03 (annual average)	ULNB
Sunoco Inc., Tulsa Refinery	OK-0126	98-014-C (M-14) (PSD permit was cancelled)	5/27/08	Process heaters	44 57.3	Refinery fuel gas	0.03 (3-hr average)	ULNB
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Sulfur recovery hot oil heater	9.6, 9.6, 35, 120	Refinery fuel gas	0.035 (3-hr rolling average)	ULNB
Marathon Petroleum Co., Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Platformer Heater Cells No. 1-3	75.7, 138.4, 73.8, 121.8, 85.1, 85.1	Refinery fuel gas	0.03 (annual average)	ULNB

Summary of BACT Determinations for NOx for Hydrogen Plants

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Dyno Nobel Louisiana Ammonia LLC	LA-0272	PSD-LA-768 (M-1)	10/14/13	Primary Reformer Furnace	956.2	Natural Gas	0.017	SCR and Low-NOx burners
Tesoro Alaska Kenai Refinery	**AK-0037**	**9923-AC010**	**03/21/00**	**Hydrogen Reformer Furnace**	**152.3**	**Natural Gas**	**0.08**	**None stated**
Arizona Clean Fuels Yuma	AZ-0046	1001205	4/14/05	Hydrogen Reformer Heater	1435	RFG or Natural Gas	0.0125	SCR and Low-NOx burners
Chevron Products Co	CA-0887	341340	3/24/99	Reformer Furnace	653	RFG	0.006 (5 ppm @ 3% O_2)	SCR
Iowa Fertilizer Co	IA-0105	12-219	10/26/12	Primary Reformer	1130	Natural Gas	0.011 (9 ppm @ 3% O_2)	SCR
Con Agra Soybean Processing Co	**IN-0104**	**129-8541-00039**	**8/14/98**	**Boiler and Hydrogen Plant Reformer**	**10**	**Natural Gas**	**0.0365**	**Low-NOx burners and FGR**
Ohio Valley Resources LLC	IN-0172	147-32322-00062	9/25/13	Primary Reformer	1006.4	Natural Gas	0.011 (9 ppm @ 3% O_2)	SCR
American Iron Reduction – Gulf Coast DRI facility	LA-0101	PSD-LA-596	3/18/96	Reformer Furnaces, 2 Units	1090	Natural Gas	0.132	Low-NOx burners
Louisiana Iron Works (Tondu) DRI Plant	LA-0107	PSD-LA-605	5/05/96	Reformer Furnace	1160.6	Natural Gas	0.13	Low-NOx Burners

Units of a comparable size to the unit proposed here are shown in boldface print.

Summary of BACT Determinations for NOx for Hydrogen Plants – Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Marathon Petroleum Co Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Hydrogen Reformer Furnace	1412.5	Purge Gas	0.0125	ULNB and SCR
Valero Refining – New Orleans LLC	LA-0245	PSD-LA-750	12/15/10	SMR Heaters	1055	Fuel Gas	0.015	ULNB and SCR
Air Products and Chemicals, Inc.	LA-0264	PSD-LA-750 (M-1)	9/04/12	Reformer	1320	Fuel Gas	0.037	ULNB and SCR
Navajo Refining Co Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Steam Methane Reformer Heater	337	Natural Gas and Reformer Off-gas	0.0125	SCR
BP Products North America	OH-0329	P0103694	8/07/09	Reformer Heater	519	RFG	0.045	Not stated
Pryor Chemical Company	OK-0134	2008-100-C (PSD)	2/23/09	Primary Reformer	Not stated	Natural Gas	Not stated	Low-NOx burners
United Refinery Co	PA-0231	62-017G	10/09/03	Hydrogen Reformer Unit	344	Refinery Gas	0.04	Low-NOx Burner, good combustion
Air Liquide America Corp Freeport	TX-0288	PSD-TX-995	6/22/01	Steam Methane Reformer	286	H2 off-gas	0.03	SCR
Diamond Shamrock Refining Co, McKee Plant	TX-0348	PSD-TX-1004	10/19/01	No 3 Reformer Charge Heaters	160.4	RFG	0.038	None stated

Summary of BACT Determinations for NOx for Hydrogen Plants – Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
ExxonMobil Oil Corp, Beaumont Refinery	TX-0393	PSD-TX-768 M-1	12/01/99	Reformer heater	Not stated	Not stated	Not stated	Not stated
Diamond Shamrock Refining Co, McKee Plant	**TX-0395**	**PSD-TX-861 M-1**	**5/23/00**	**Reformer Charge Heater**	**248**	**RFG**	**0.05**	**Not stated**
Valero Refining Texas LP, Corpus Christi Refinery, East Plant	TX-0443	P1023	1/01/05	Reformer HDS Charger and Stripper	Not stated	RFG	Not stated	Not stated
Valero Refining Texas LP, Corpus Christi Refinery, East Plant	TX-0442	P1023	1/01/05	Steam Methane Reformer Heater	Not stated	RFG	Not stated	Not stated
Air Products	TX-0526	NA 63 and 39693	8/18/06	Reformer Furnace	1373	Steam	0.06	Not stated
Diamond Shamrock Refining Co, McKee Plant	TX-0580	92928 HAP63	12/30/10	Hydrogen Production Unit Furnace	355.65	RFG with natural gas	0.01	Low-NOx burners and SCR
Equistar Chemicals LP	TX-0614	PSD-TX-1280	10/25/12	Methanol Reformer	Not stated	Natural Gas	0.01	SCR
Nat Gasoline LLC Beaumont Plant	TX-0657	PSD-TX-1340	5/16/14	Reformer	1552	Natural gas and RFG	0.01	SCR

2. CO BACT Review

Carbon monoxide is a product of the chemical reaction between carbonaceous fuels and oxygen. CO occurs as the product of combustion in fuel-rich mixtures. In fuel-lean mixtures, CO can result due to poor mixing of fuel and air or because of low temperatures in the combustion zone.

Step 1. Identify Available Control Technologies
A search of the RBLC and literature sources identified the following technologies for control of CO emissions from process heaters:

- Good Combustion Practice;
- Ultra-Low NOX Burners (ULNB);
- Regenerative Thermal Oxidation (RTO); and
- Regenerative Catalytic Oxidation (RCO).

Good Combustion Practice
Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air, temperature, residence time, and mixing are incorporated in the combustion design and operation, CO emissions are minimized. The design of modern, efficient combustion equipment is such that there is adequate turbulence in the flue gas to ensure good mixing, a high temperature zone (greater than 1,800°F) to complete burnout, and sufficient residence time at the high temperature (one to two seconds). Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions.

ULNB
ULNB technology has developed to provide increasing lower levels of NOx emissions. However, when operated using good combustion practices, ULNB can also provide significant reductions in CO emissions.

Regenerative Thermal Oxidation
Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Thermal oxidation requires raising the flue gas temperature to 1,300 to 2,000°F in order to complete the CO oxidation. Depending on specific furnace and thermal oxidizer operational parameters (fuel gas heating value, excess oxygen in the flue gas, flue gas temperature, and oxidizer temperature) raising the flue gas temperature can require an additional heat input of 10 to 25% above the process heater heat input. Also, depending on the design of the thermal oxidizer, emissions of NO_X, SO_2 and PM_{10} / $PM_{2.5}$ can be 10 to 25% higher than emissions without a thermal oxidizer.

Regenerative Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible without the catalyst. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650 to 1,000°F. This can require from 0 to 10% additional fuel and a resulting similar increase in other pollutant emissions. Catalytic oxidizers cannot be used on waste gas streams containing significant amounts of particulate matter as the particulate deposits foul the catalyst and prohibit oxidation. High temperatures can also accelerate catalyst deactivation; however, that is normally not a concern with flue gas from process heaters and boilers.

Step 2. Eliminate Technically Infeasible Options

A search of the RBLC database indicated that thermal and catalytic oxidation has rarely been applied to process heaters or boilers. Typically, higher concentrations of CO in the pollutant stream are needed to justify the use of thermal oxidation and catalytic oxidation. However, neither control option can be eliminated as technically infeasible. Therefore, all of the technologies mentioned above will be examined for energy, environmental, and economic impacts.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The remaining options are ranked based on effectiveness.

Technology	**Control Efficiency %**
Good Combustion Practices	Base case
ULNB	25-75
Regenerative Thermal Oxidizer	75-95
Regenerative Catalytic Oxidation	75-95

Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic Impacts

The technologies for CO emission controls are evaluated in this section, including their effectiveness, and any energy, environmental, and economic impacts.

A review of BACT determinations for refinery heaters did not identify the use of add-on controls as achieved in practice. Instead, low-NOx burners have been used – many which also provide for low CO emissions.

A range of costs is based on EPA's Air Pollution Control Technology Fact Sheet for regenerative incinerators (www.epa.gov/ttn/catc/dir1/fregen.pdf). From a baseline of 0.082 lb CO/MMBtu (AP-42), the proposed ultralow-NOx burners will reduce emissions to an estimated 0.04 lb CO/MMBtu. For cost-effectiveness calculations it is assumed that the RTO or RCO can reduce CO by an additional 90%.The add-on control equipment is sized based on air flow, which varies from about 2,000 scfm for a 10 MMBtu/hr heater to 27,000 scfm for a 125 MMBtu/hr heater. Annualized costs [2002 basis] have been estimated to range from \$8 - \$33 per scfm for an RTO and \$11 - \$42 per scfm for a RCO. Using the average of the ranges, the incremental cost effectiveness is determined to be approximately \$37,500/ton CO controlled by an RTO and approximately \$48,500/ton CO controlled by a RCO. There is no bright line rule for cost-effectiveness of CO controls, but since incremental cost effectiveness of the add-on controls is two orders of magnitude greater than the cost effectiveness of for the ultra-low NOx burner the RTO and RCO control costs are not considered cost effective.

<u>RTO</u>
Installation costs and operating costs for RTO (mostly from the 10 to 25% increase in fuel consumption) can be significant. In addition, the use of a thermal oxidizer can significantly increase the emissions of NOx from the process heaters. A search of the RBLC indicated that thermal oxidation has not been selected as BACT for control of CO from small process heaters. Therefore, based on the additional use of energy, the increase in emissions of other pollutants, the associated costs, and no previous documentation of thermal oxidation as BACT; thermal oxidation is eliminated from further consideration.

<u>RCO</u>
Cost levels for RCO are also considered to be economically infeasible for BACT. Also, an environmental consideration is the disposal of spent catalyst, which is considered a hazardous material. A search of the RBLC and recently issued permits in attainment areas indicated that catalytic oxidation was rarely selected as BACT. Therefore, based on the additional use of energy, the possible increase in emissions of other pollutants, the associated costs, and no previous documentation of catalytic oxidation as BACT; catalytic oxidation is eliminated from consideration as BACT for this project.

<u>UNLB</u>
The proposed heaters for this project are small (<250 MMBTUH) and are related to process units downstream of crude units. The following table presents a summary of selected BACT determinations for CO emissions for similar process heaters within the last six years. A review of the RBLC database indicated that use of ULNB was selected as BACT for a number of PSD permits. These determinations were usually made on the basis that use of ULNB was BACT for NOx and would also be selected as BACT for CO. As the ULNB technology has achieved lower emissions of NOx, the burners have also provided lower emissions of CO. Recent BACT determinations for small process heaters <100 MMBTUH with ULNB and/or good combustion practices have shown CO emissions ranging from 0.04 to 0.08 lb/MMBTU.

<u>Good Combustion Practices</u>

Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. There is no increased energy requirement or increased pollutants with good combustion practice. The RBLC database lists this option as a prevalent form of BACT for controlling CO emissions from process heaters and boilers.

Step 5. Select BACT and Document the Selection as BACT

The new process heaters for the project will be equipped with ULNB. HFTR will also follow good combustion practices. The combination of ULNB and good combustion practice is selected as BACT, at the emission rate of 0.04 lb CO/MMBTU (3-hour average).

The following regulations contained within 40 CFR 60 were reviewed with regards to the new process heaters, and CO emissions and NOx emissions discussed in the last section:

- Subpart J – Standards of Performance for Petroleum Refineries;
- Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
- Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units that Commenced Construction After June 9, 1989.

NSPS Subpart Ja includes a NOx emission limit for process heaters with rated capacities greater than 40 MMBTUH of 40 ppm NOx by volume, dry basis corrected to 0% excess air, on a 24-hour rolling average basis, which is approximately equivalent to 0.042 lbs NOx/MMBTU. The NOx emission limit proposed for the new heaters is more stringent, and therefore compliant with the currently-stayed NSPS Subpart Ja limit. Subpart Ja does not include CO limits for fuel gas combustion devices such as the new heaters. NSPS Subpart J does not include NOx or CO emission limits for fuel gas combustion devices. In addition, the regulations are not applicable to these heaters because of their date of manufacture. Subpart Dc does not include NOx or CO emission limits for gas-fired boilers. The only requirements for these boilers are initial notification and recordkeeping of the fuel combusted during each calendar month. Lastly, there are no currently applicable MACT standards with limits for NOx or CO.

Summary of BACT Determinations for CO for Process Heaters, <100 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
HFTR Woods Cross Refinery, UT	n/a	DAQEIN1012 3 0041-12	July 2012	New - Reactor Charge Heater, FCCU #2 Feed Heater, Asphalt Heaters, Heater Oil Furnace Reactor Charge Furnace, Vacuum Furnace Heater	42.1, 45, 0.8, 14, 99, 130	Refinery fuel gas	0.08 (1-hour average)	ULNB, good combustion practices
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619 (M-5) (draft)	11/17/09	CPF Heaters H-39-03 and H-39-02 Heaters 2008-1 - 2008-9 DHT Heaters 4-81 and 5-81	68 36 70	Refinery fuel gas	0.08 (one-hr average)	ULNB, good combustion practices

Summary of BACT Determinations for CO for Process Heaters, <100 MMBTUH - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Total Refining – Port Arthur	TX-0539	PSD-TX-1073M1	11/6/09	VDU Heater; KNHT Charge Heater; DHT-3 Charge Heater	99 42 50	Refinery fuel gas	0.07 (one-hr average)	Good burner technology
ConocoPhillips, Ponca City Refinery	OK-0136	2007-042-C PSD	2/09/09	NH-1 New Naphtha Splitter Reboiler	131.3, 45, 125, 98	Refinery fuel Gas	0.04 (annual average)	ULNB, good combustion practices
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	ROSE 2 Hot Oil Heater	9.6, 9.6, 35, 120	Refinery fuel gas	0.09 (3-hr rolling average)	ULNB, gaseous fuel combustion only
Marathon Petroleum Co., Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Platformer Heater Cells No. 1-3, and HCU Fractioner Heater	75.7, 138.4, 73.8, 121.8, 85.1, 85.1	Refinery fuel gas	0.04 (3-run average)	ULNB, proper design, operation, and good engineering practices

Summary of BACT Determinations for CO for Hydrogen Plants

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Tesoro Alaska Kenai Refinery	**AK-0037**	**9923-AC010**	**03/21/00**	**Hydrogen Reformer Furnace**	**152.3**	**Natural Gas**	**0.04**	**None stated**
Arizona Clean Fuels Yuma	AZ-0046	1001205	4/14/05	Hydrogen Reformer Heater	1435	RFG or Natural Gas	0.01	Not stated
Chevron Products Co	CA-0887	341340	3/24/99	Reformer Furnace	653	RFG	0.0194	Good combustion
Iowa Fertilizer Co	IA-0105	12-219	10/26/12	Primary Reformer	1130	Natural Gas	0.0194	Good combustion
CF Industries Nitrogen LLC, Port Neal Nitrogen Complex	IA-0106	PN 13-037	7/12/13	Primary Reformer	1062.6	Natural Gas	0.0194	Good operating practices, natural gas fuel
Con Agra Soybean Processing Co	**IN-0104**	**129-8541-00039**	**8/14/98**	**Boiler and Hydrogen Plant Reformer**	**10**	**Natural Gas**	**0.074**	**Combustion control**
Ohio Valley Resources LLC	IN-0172	147-32322-00062	9/25/13	Primary Reformer	1006.4	Natural Gas	0.043	Good combustion
ConocoPhillips Wood River Refinery	IL-0103	6050052	8/05/08	Hydrogen Plant 2	Not stated	RFG	Not stated	Not stated

Summary of BACT Determinations for CO for Hydrogen Plants - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Marathon Petroleum Co Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Hydrogen Reformer Furnace	1412.5	Purge Gas	0.04	Proper design & operation, good engineering practices
Marathon Petroleum Co Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Hydrogen Plant Flare	2472	H2 Plant Feed Gas	0.008	Comply with 60.18
Valero Refining – New Orleans LLC	LA-0245	PSD-LA-750	12/15/10	SMR Heaters	1055	Fuel Gas	0.08	Proper equipment designs and operations, good combustion practices
Navajo Refining Co Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Steam Methane Reformer Heater	337	Natural Gas and Reformer Off-gas	0.06	Gas fuel
BP Products North America	OH-0329	P0103694	8/07/09	Reformer Heater	519	RFG	0.046	Not stated
Pryor Chemical Company	OK-0134	2008-100-C (PSD)	2/23/09	Primary Reformer	Not stated	Natural Gas	Not stated	Good combustion practices
Pryor Chemical Company	OK-0135	2008-100-C (PSD)	2/23/09	Primary Reformer	Not stated	Natural Gas	Not stated	Good combustion practices

Summary of BACT Determinations for CO for Hydrogen Plants - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
United Refinery Co	PA-0231	62-017G	10/09/03	Hydrogen Reformer Unit	344	Refinery Gas	0.082	Good combustion practice
Air Liquide America Corp Freeport	TX-0288	PSD-TX-995	6/22/01	Steam Methane Reformer	286	H2 off-gas	0.024	Not stated
Diamond Shamrock Refining Co, McKee Plant	**TX-0348**	**PSD-TX-1004**	**10/19/01**	**No 3 Reformer Charge Heaters**	**160.4**	**RFG**	**0.08**	**None stated**
ExxonMobil Oil Corp, Beaumont Refinery	TX-0393	PSD-TX-768 M-1	12/01/99	Reformer heater	Not stated	Not stated	Not stated	Not stated
Diamond Shamrock Refining Co, McKee Plant	**TX-0395**	**PSD-TX-861 M-1**	**5/23/00**	**Reformer Charge Heater**	**248**	**RFG**	**0.03**	**Not stated**
Valero Refining Texas LP, Corpus Christi Refinery, East Plant	TX-0443	P1023	1/01/05	Reformer HDS Charger and Stripper	Not stated	RFG	Not stated	Not stated
Air Products	TX-0526	NA 63 and 39693	8/18/06	Reformer Furnace	1373	Steam	0.016	Not stated

Summary of BACT Determinations for CO for Hydrogen Plants - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Diamond Shamrock Refining Co, McKee Plant	TX-0580	92928 HAP63	12/30/10	Hydrogen Production Unit Furnace	355.65	RFG with natural gas	0.037 (50 ppm @ 3% O_2)	Good combustion practices
Nat Gasoline LLC Beaumont Plant	TX-0657	PSD-TX-1340	5/16/14	Reformer	1552	Natural gas and RFG	0.037 (50 ppm @ 3% O_2)	Good combustion practices
Dyno Nobel Louisiana Ammonia LLC	LA-0272	PSD_LA-768	10/08/12	Primary Reformer Furnace	956.2	Natural Gas	0.05	Good combustion practices, proper design of firebox components, proper air-to-fuel ratio

Summary of BACT Determinations for PM_{10} for Process Heaters, <100 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Hydrocracker reboiler	35	Refinery fuel gas	0.0075	Nothing stated
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Hydrocracker fractionator furnace	9.6	Refinery fuel gas	0.0075	Nothing stated

Summary of BACT Determinations for PM for Hydrogen Plants

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Dyno Nobel Louisiana Ammonia LLC	LA-0272	PSD-LA-768 (M-1)	10/14/13	Primary Reformer Furnace	956.2	Natural Gas	0.009	Good combustion practices, proper design of firebox components, proper air-to-fuel ratio
Tesoro Alaska Kenai Refinery	**AK-0037**	**9923-AC010**	**03/21/00**	**Hydrogen Reformer Furnace**	**152.3**	**Natural Gas**	**0.005**	**None stated**
Air Liquide America Corp Freeport	TX-0288	PSD-TX-995	6/22/01	Steam Methane Reformer	286	H2 off-gas	0.012	None stated
Ohio Valley Resources LLC	IN-0172	147-32322-00062	9/25/13	Primary Reformer	1006.4	Natural Gas	0.0019	Good combustion
Arizona Clean Fuels Yuma	AZ-0046	1001205	4/14/05	Hydrogen Reformer Heater	1435	RFG or Natural Gas	0.0075	Not stated
Chevron Products Co	CA-0887	341340	3/24/99	Reformer Furnace	653	RFG	0.0075	Gas fuel
American Iron Reduction – Gulf Coast DRI	LA-0101	PSD-LA-596	3/18/96	Reformer Furnace	1090	Natural Gas	0.003 gr/DSCF	Scrubbing spent gas from DRI Furnaces

Summary of BACT Determinations for PM for Hydrogen Plants - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Louisiana Iron Works (Tondu) DRI Plant	LA-0107	PSD-LA-605	5/05/96	Reformer Furnace	1160.6	Natural gas	0.001 gr/DSCF	Scrubbing spent gas from DRI Furnaces
Marathon Petroleum Co Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Hydrogen Reformer Furnace	1412.5	Purge Gas	0.0075	Proper design, operation, and good engineering practices
Navajo Refining Co Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Steam Methane Reformer Heater	337	Natural Gas and Reformer Off-gas	0.0075	Gas fuel combustion only
United Refinery Co	PA-0231	62-017G	10/09/03	Hydrogen Reformer Unit	344	Refinery Gas	0.005	Good combustion practices
Diamond Shamrock Refining Co, McKee Plant	TX-0348	PSD-TX-1004	10/19/01	No 3 Reformer Charge Heaters	160.4	RFG	0.038	None stated
ExxonMobil Oil Corp, Beaumont Refinery	TX-0393	PSD-TX-768 M-1	12/01/99	Reformer heater	Not stated	Not stated	Not stated	Not stated
Diamond Shamrock Refining Co, McKee Plant	**TX-0395**	**PSD-TX-861 M-1**	**5/23/00**	**Reformer Charge Heater**	**248**	**RFG**	**0.01**	**Not stated**

Summary of BACT Determinations for PM for Hydrogen Plants - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Valero Refining Texas LP, Corpus Christi Refinery, East Plant	TX-0443	P1023	1/01/05	Reformer HDS Charger and Stripper	Not stated	RFG	Not stated	Not stated
Valero Refining Texas LP, Corpus Christi Refinery, East Plant	TX-0442	P1023	1/01/05	Steam Methane Reformer Heater	Not stated	RFG	Not stated	Not stated
Air Products	TX-0526	NA 63 and 39693	8/18/06	Reformer Furnace	1373	Steam	0.012	Not stated
Nat Gasoline LLC Beaumont Plant	TX-0657	PSD-TX-1340	5/16/14	Reformer	1552	Natural gas and RFG	0.005	Good combustion practices and fuel selection
Iowa Fertilizer Co	IA-0105	12-219	10/26/12	Primary Reformer	1130	Natural Gas	0.0024	Good combustion practices
CF Industries, Port Neal Nitrogen Complex	IA-0106	PN 13-037	7/12/13	Primary Reformer	1062.6	Natural gas	0.0024	Good operating practices and natural gas fuel

Summary of BACT Determinations for PM for Hydrogen Plants - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Valero Refining – New Orleans LLC	LA-0245	PSD-LA-750	12/15/10	SMR Heaters	1055	Fuel Gas	0.0075	Proper equipment designs and operation, good combustion practices
Air Products and Chemicals, Inc.	LA-0264	PSD-LA-750 (M-1)	9/04/12	Reformer	1320	Fuel Gas	0.0085	Proper equipment designs and operation, good combustion practices ULNB and SCR
Pryor Chemical Company	OK-0134	2008-100-C (PSD)	2/23/09	Primary Reformer	Not stated	Natural Gas	Not stated	Low-NOx burners
BP Products North America	OH-0329	P0103694	8/07/09	Reformer Heater	519	RFG	0.045	Not stated

3. PM_{10} & $PM_{2.5}$ Emissions from New Process Heaters

PM_{10} is particulate matter (PM) less than 10 microns in diameter produced by combustion. PM_{10} consists of two parts, filterable and condensable. Filterable PM_{10} is the material that is captured on the filter used in the EPA Method 5 test. Condensable PM_{10} is particulate that passes through the filter as a gas and is measured using EPA Reference Method 202. According to AP-42, filterable PM emissions from gaseous fuels such as refinery fuel gas are typically lower than emissions from solid fuels. Particulate matter from refinery gas or natural gas combustion is usually composed of larger molecular weight hydrocarbons that have not been fully combusted. Based upon the literature sources reviewed, nearly all particulate from refinery gas or natural gas combustion sources is $PM_{2.5}$. Therefore, for the BACT analysis for process heaters, $PM_{2.5}$ and PM_{10} are considered equivalent.

Widely accepted petroleum industry references and permit determinations support the basis that refinery gas combustion PM is mainly in the $PM_{2.5}$ size range. Industry research has confirmed this fact. In "$PM_{2.5}$ Speciation Profiles and Emission Factors from Petroleum Industry Gas-Fired Sources." (Wien, England, et. Al., www.epa.gov/ttnchie1/conference/ei10/poster/wien.pdf), it is stated "The majority of primary emissions from combustion is found in the $PM_{2.5}$ or smaller size range, especially for devices equipped with particulate emissions control equipment and for clean burning fuels such as gas." The Refinery Emissions Estimation Protocol for Petroleum Refineries (Version 2.1.1, May 2011) Section 4.5 recommends calculating PM emissions from refinery gas combustion using EPA AP-42 Section 1.4 emission factors developed for natural gas combustion in boilers and heaters. The condensable PM fraction from Table 1.4-2, assumed to be $PM_{2.5}$, is 75%. The California Air Resources Board, in PM speciation profiles used for emission inventories (www.arb.ca.gov/ei/speciate/speciate.htm#filelist), cites the fraction of PM emissions less than 2 micron from refinery process heaters as 93%. As a worst-case assumption, all PM_{10} is assumed to be $PM_{2.5}$.

Step 1. Identify All Available Control Technologies
The following is a list of control technologies, which were identified for controlling PM_{10} / $PM_{2.5}$ emissions:

- Good combustion practices;
- Use of low sulfur gaseous fuels;
- Proper design and operation;
- Wet gas scrubber;
- Electrostatic precipitator (ESP);
- Cyclone; and
- Baghouse / fabric filters.

By maintaining the heaters in good working order per manufacturer specifications with low sulfur gaseous fuels, emissions of PM_{10} / $PM_{2.5}$ are reduced.

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected, as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. Some precipitators remove the particles by washing with water. ESPs are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations.

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube. Cyclones are generally used to reduce dust loading and collect large particles.

Step 2. Eliminate Technically Infeasible Control Options

None of the add-on control devices were identified as being suitable for the process heaters burning gaseous fuels due to both the extremely low concentration of small particulates expected in gas streams from this type of equipment. PM_{10} / $PM_{2.5}$ concentrations in the refinery fuel and natural gas-fired boilers and heaters are even less than the concentrations guaranteed by the cyclones, ESPs, fabric filters, and wet scrubbers. Therefore, wet scrubbers, ESPs, cyclones, and fabric filtration (baghouses) were rejected as BACT for PM_{10} / $PM_{2.5}$ emissions from heaters and boilers.

Step 3. Rank Remaining Control Options

The remaining control option is the utilization of good combustion practices.

Step 4. Evaluate Remaining Control Options
The concept of applying combustion controls and appropriate furnace design or "proper combustion" to minimize PM_{10} / $PM_{2.5}$ emissions include adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimization of these factors for PM_{10} / $PM_{2.5}$ control can result in an increase in the NOx emissions. Heater and boiler designers strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants. Thus, the only control technology identified in the RBLC database for the refinery fuel or natural gas-fired process heaters is a work practice requirement to adhere to good combustion practices and use of low sulfur gaseous fuel. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5. Select BACT
A review of the RBLC as well as other databases indicated that the most stringent control technologies for PM_{10} / $PM_{2.5}$ are good combustion practices and use of gaseous fuel. Based upon review of the database, the selected PM_{10} / $PM_{2.5}$ BACT emission limit for the proposed new process heaters is based on manufacturer data at 0.0075 lb/MMBTU PM_{10} / $PM_{2.5}$, utilizing proper equipment design and operation, good combustion practices, and gaseous fuels.

4. BACT for Greenhouse Gases

A. New Process Heaters

Greenhouse gas (GHG) emissions from process heaters include primarily carbon dioxide (CO_2) with lesser amounts of nitrous oxide (N_2O) and methane (CH_4). The majority of the total GHG emissions, expressed as CO_2e are CO_2 emissions. CO_2 is a product of combustion of fuel containing carbon, such as refinery fuel gas and natural gas. Refinery fuel gas is a mixture of light C1 to C4 hydrocarbons, hydrogen, hydrogen sulfide (H_2S), and other gases.

A search of EPA's RBLC shows no BACT determinations for gas-fired heaters smaller than 100 MMBTUH.

Step 1. Identify All Available Control Technologies
Control technologies identified for reducing GHG emissions from process heaters include:

- Energy-efficient design and good combustion practices;
- Use of low-carbon fuel;
- Carbon capture and sequestration (CCS).

Post-combustion capture systems use chemical or physical absorption/adsorption processes, which may include solvent scrubbing, high temperature sorbents, ionic liquids, biological capture using algae ponds, and membrane technology.

Step 2. Eliminate Technically Infeasible Control Options

The identified control options of energy efficient design and combustion practices and low-carbon fuels are technically feasible and will be reviewed further. The purpose of carbon capture and sequestration (CCS) is to produce a concentrated stream that can be readily transported to a CO_2 storage site. Options to capture CO_2 emissions include oxy-combustion and post-combustion methods. If either carbon capture technology can be utilized, after capture, a compression system to compress the CO_2 is needed to prepare the CO_2 for transport to a permanent geological storage site such as oil and gas reserves and underground saline formations, and to inject the captured CO_2 into the storage site. In oxy-combustion carbon capture, nearly pure oxygen is used for combustion instead of air which results in an exhaust gas that is comprised of mainly H_2O and concentrated CO_2. The process uses an air separation unit to remove the nitrogen component from the air. The oxygen-rich stream is fed to the combustion unit so the resulting exhaust gas contains a concentration of CO_2 of 80% or higher. This technology is still in the research stage.

In addition to oxy-combustion carbon capture, post-combustion capture systems are currently under commercial development. Post-combustion capture is an "end of pipe" technology that involves separating CO_2 from flue gas consisting mainly of nitrogen, water, CO_2 and other impurities.

Carbon capture technologies are not yet commercially available, and appropriate geologic formations have not been proven for long-term underground storage in the vicinity of Tulsa, OK. It is unlikely that there are existing pipelines running through metropolitan Tulsa available for transporting the CO_2. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, carbon capture and sequestration is not considered to be a technically feasible control option at this time, and is therefore eliminated from further consideration in this analysis. In addition, since CCS is not yet commercially available, it is not possible to accurately estimate control costs.

The nearest CO_2 injection location was researched for determining feasibility of CO_2 injection. The applicant looked up current CO_2 injection projects at http://www.natcarbviewer.com sponsored by US Dept of Energy. There is a CO_2 injection study in the development phase about 500 miles to the west in Texas (Chapparal Energy's Farnsworth Unit EOR Field Project), and a small scale injection project sponsored by the University of Kansas about 150 miles to the northwest in the Wellington Field near Wichita, Kansas. Since these injection sites are not commercially available and would require the construction of a lengthy pipeline, they are not considered feasible at this time.

Step 3. Rank Remaining Control Options

The use of energy efficient design and combustion practices and low-carbon fuels to reduce GHG emissions from the proposed process heaters at HFTR will be standard for the proposed project.

Step 4. Evaluate Remaining Control Options
Possible GHG reduction measures and good combustion practices for new process heaters fired on refinery fuel gas include:

- Draft controls can be installed to limit excess air to an optimal level to reduce energy usage of the burners. Regular maintenance of the draft air intake systems can reduce energy usage;
- Air preheating – the flue gases of the furnace can be used to preheat the combustion air and increase the thermal efficiency of the furnace;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation; and
- Instrumentation to monitor and control excess oxygen levels in the optimal zone to complete combustion while maximizing thermal efficiency.

To the extent that combustion control and good practices increase fuel efficiency, they are an effective means for reducing CO_2 emissions. Preheating the combustion air reduces the amount of fuel required and ultimately lowers GHG emissions since less fuel is being combusted. Maximizing combustion efficiency through process heater burner design and operation further reduces CH_4 emissions and reduces operating cost.

<u>Low-Carbon Fuel</u>
Gaseous fuels such as refinery fuel gas and natural gas reduce CO_2 emissions from combustion relative to burning solid or liquid fuels such as coal or distillate oils. HFTR will primarily use refinery fuel in the new process heaters.

Step 5. Select BACT
The BACT selection for GHG emissions from new process heaters is good combustion practices, use of low-carbon fuel, and energy efficient design. This includes good air/fuel mixing in the combustion zone, good burner maintenance and operation, sufficient residence time to complete combustion, high temperatures and low oxygen levels in the primary combustion zone, proper fuel gas supply system design and operation, and excess oxygen levels high enough to complete combustion while maximizing thermal efficiency. Oxygen monitors and intake airflow monitors will be used to optimize the fuel/air mixture and limit excess air. As available from the manufacturer, air preheater packages will be installed, consisting of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convection section exchange heat with the incoming combustion air.

For a CO_2e BACT emission limitation for new process heaters, HFTR proposes the value be established in terms of lb CO_2/MMBTU, based upon the manufacturer heat input rating and a default refinery gas CO_2 factor emission factor. BACT is selected as a limit of 146 lb CO_2/MMBTU to include a safety margin for variations in fuel carbon content.

B. New Hydrogen Unit: Greenhouse Gases

In addition to combustion products discussed above, the hydrogen plant generates CO_2e as a process emission. Since CO_2e is not typically feasible to control at end-of-stack, the available options to reduce CO_2e emissions focus on potential improved process efficiency, leading to improved fuel efficiency, rather than end-of-stack types of control systems.

A stepwise top-down review of the options to reduce CO_2e emissions from the new hydrogen plant is provided following.

Step 1. Identify Available Control Technologies
Potentially-applicable CO_2e control technologies include add-on controls, inherently lower-emitting processes, practices, and designs, and combinations of the two. Since CO_2e is created as an unavoidable product of the steam reforming reaction, identification of available controls will focus on lower-emitting processes, practices, and designs. Although many alternatives will be eliminated in following steps, Step 1 should include the potential and relevant options. The following references were consulted in identifying potential control measures:

- EPA RBLC Clearinghouse
- "Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR Guide for Energy and Plant Managers" (Document Number LBNL-56183, February 2005)
- "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry" (US EPA, October 2010); and
- Other BACT determinations for similar processes and equipment.

The following potential GHG controls were identified:

- Carbon capture and sequestration (CCS);
- Combined heat and power cogenerations (CHP);
- Process integration ("PINCH");
- Combustion air and feed/steam preheat;
- Hydrogen purification process evaluation;
- Hydrogen production optimization;
- Maintenance and fouling control;
- Combustion air controls;
- New burner designs;
- Adiabatic pre-reformer; and
- Alternative fuels.

Carbon capture and sequestration (CCS) is a "tailpipe" control process in which CO_2 is injected into deep aquifers, depleted oil and gas reservoirs, unmineable coal seals, or existing oil fields (as an enhanced oil recovery process). The process may be conducted either by using an amine unit to separate out CO_2 from the remainder of flue gases, or the entire stream may be injected.

Combined heat and power cogeneration (CHP) uses hot exhaust gases for generation of steam for turning electrical generation equipment. The process relies on there being significant temperature and oxygen concentrations in the exhausts.

Process Integration (PINCH) refers to synergistic designs where heating and cooling are provided by various process streams within a unit. Combustion and reactant pre-heating may be accomplished by cooling product streams.

Combustion air and feed/steam preheat refers to the use of heat recovery system to preheat the feed/steam and combustion air temperature. This option may result in a decrease in fuel consumption, because less heat must be created by combustion.

Hydrogen purification process evaluation is selecting the most efficient method of purifying hydrogen for usage, minimizing waste along with minimizing the amounts of fuels and raw materials and emissions. The three main hydrogen purification processes are pressure swing absorption (PSA), membrane separation, and cryogenic separation.

Hydrogen production optimization refers to utilizing hydrogen generated in other steps such as catalytic reforming or platforming in preference to operating a reformer.

Maintenance and fouling control is used in heaters and heat exchangers to prevent or eliminate fouling which reduces the efficiency of heat exchange.

Combustion air controls minimize the amount of air introduced into process heaters. Any air which enters a heater absorbs heat and increases the amount of fuel which must be combusted.

GHG BACT Determinations for Reformer Heaters at Petroleum Refineries

RBLC ID	Facility	State	Permit Issuance Date	BACT Limit
ND-0031	Dakota Prairie Refining	ND	02/21/13	21,094 ton CO_2e (22 MMBTUH Heater)
NA	Wynnewood Refinery	OK	01/06/14	120,280 lb CO_2e per MMSCF Natural Gas Feed
LA-0263	ConocoPhillips Alliance Refinery	LA	07/25/12	0.05 lb CO_2e/SCF H_2, Efficient H_2 Purification Process

Newer burner designs combust fuel more efficiently, resulting in less fuel being needed.

Adiabatic pre-reforming is related to process integration in which a nickel catalyst is used to commence reforming at 900°F using waste heat from the reformer convection section.

Alternate fuels change from traditional fossil fuels to biomass.

A search of EPA's RBLC showed two BACT determinations for similar-sized small reformers at petroleum refineries. The results of the search are shown above. RBLC did not provide details on the control technologies or emission calculations for the determinations. ODEQ recently evaluated a reformer at Wynnewood Refining.

Step 2. Eliminate Technically Infeasible Options

The list of potential control technologies identified in Step 1 are evaluated for technical feasibility. EPA considers technologies to be technically feasible if:

- They have been demonstrated and operated successfully at a similar source,
and
- They are available and applicable to the source under review.

Technologies in the pilot or R&D phases are not considered to be "available."

CCS: One end-of-stack control option to be considered is geologic sequestration of GHG. However, sequestration is not yet commercially available and appropriate. Geologic formations have not been proven for long-term underground storage in the vicinity of Tulsa, OK. Transportation of the CO_2 through metropolitan Tulsa presents numerous issues. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and would require further study. Therefore, geologic sequestration is not considered to be a technically feasible control option at this time, and is therefore eliminated from further consideration in this analysis. In addition, since sequestration is not yet commercially available, it is not possible to accurately estimate control costs.

Alternative Fuels: Natural gas and refinery fuel gas are the lowest GHG-emitting fuels and are feedstock for the reformer process. Alternative fuels would have to be gasified prior to introduction into the process. They are, therefore, infeasible as CO_2 emission controls.

Adiabatic Pre-Reforming: Instead of using waste heat for other purposes, waste heat may be used in an adiabatic pre-reforming process. The hydrogen plant design will consider this process if other waste heat options are not implemented.

Cogeneration: While technically feasible, this option pre-supposes that sufficient waste heat is available and there is sufficient oxygen in gases to support combustion. For this option to be used, other waste heat recovery options must be abandoned and excess air must be used.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The following table shows the remaining controls:

Control Technology Option	Estimated GHG Emissions Reduction	Estimated Energy Efficiency Increase	Reference
Maintenance and fouling control	1-10% of process heater emissions	3-6%	October 2010 EPA GHG BACT Guidance & Energy Star Guide (LBNL-56183, February 2005)
Combustion Air and Feed Steam Preheat	5% compared to typical reformer	5% compared to typical reformer	October 2010 EPA GHG BACT Guidance
Combustion Air Controls	1-3% of heater emissions	1-3%	October 2010 EPA GHG BACT Guidance
Process Integration (PINCH)	N/A	N/A	October 2010 EPA GHG BACT Guidance
Hydrogen Production Optimization	N/A	N/A	October 2010 EPA GHG BACT Guidance
Hydrogen Purification Process Evaluation	N/A	N/A	October 2010 EPA GHG BACT Guidance
New Burner Designs	N/A	N/A	Energy Star Guide (LBNL-56183, February 2005)

Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic Impacts

Under the top-down approach, the highest ranking option is considered first and is evaluated on the basis of cost and collateral environmental impact. Since the highest ranked option is incorporated in the proposed reformer, along with several other options, costs have not been evaluated.

Step 5. Select BACT and Document the Selection as BACT

The following combination of energy efficiency techniques is selected as BACT:

- Maintenance and fouling control;
- Steam/feed preheating;
- Combustion air controls;
- Process integration (energy efficient design);
- Reformer with PSA hydrogen purification; and
- Latest proven burner designs.

Emissions of CO_2e will be limited to 146 lb/MMBTU in the permit for EUGs 39 and 40.

SECTION VIII. EVALUATION OF AIR QUALITY IMPACTS AND DETERMINATION OF MONITORING REQUIREMENTS

Introduction

For the minor changes related to this modified PSD construction permit the applicant was required to submit updated Class II area air dispersion modeling analysis for NO_2, PM_{10}, $PM_{2.5}$, and CO. These updated analyses addressed both NAAQS and Increment modeling and related cause or contribute analyses. The updated modeling analyses indicates negligible changes in the modeled impacts and the conclusions of the original PSD construction permit did not change. Because the changes were did not result in a significant change in impacts, the Class II visibility analysis and Class I screening analysis were not updated.

Changes related to the modeling since issuance of Permit No. 2012-1062-C (M-1) PSD on April 20, 2015, have been incorporated where applicable and discussion included for historical purposes has also been noted. EPA comments and the AQD responses to EPA comments from the original PSD construction permit are available as part of the original PSD construction permit record. Since issuance of the original PSD construction permit, the construction permit and related modeling analysis was revised in Permit No. 2012-1062-C (M-6) PSD issued on November 12, 2015. In the modified permit, the NO_2, PM_{10}, $PM_{2.5}$, and CO modeling was updated to incorporate the proposed changes and additional changes to the nearby source inventory.

In June 2016, the AQD Air Dispersion Modeling Guidelines was updated and part of this update was to incorporate a newer (2011-2015) meteorological dataset. The guidance allows for an 18-month transition period when revising previous modeling analyses. However, the meteorological data is required to be processed using the most recent version of AERMET. The modeling analyses for this modified construction permit was received in September 2017, which is within the 18 month transition period of the Guidelines.

On January 17, 2017, EPA published updates to 40 CFR Part 50, Appendix W, *Guideline on Air Quality Models*. Some of the changes to Appendix W were applicable to and affected the revised modeling submittal. The updates to Appendix W became effective on February 16, 2017, and a one year transition period for the updates ended on January 17, 2018. This permit application was administratively complete on September 5, 2017, which is within the applicable transition period for the updates of Appendix W. In June of 2017, the AQD Air Dispersion Modeling Guidelines was updated to incorporate these changes. Where applicable, changes to the modeling analyses related to the updates in Appendix W have been incorporated or addressed.

Model Selection and Description

The original PSD modeling was conducted in accordance with the modeling protocol dated April 22, 2013, and reviewed by AQD, and the subsequent draft *Request to use Tier 3 Plume Volume Molar Ratio Method and/or Ozone Limiting Method for NO_2 Modeling* (draft March 12, 2014, updated May 19, 2014) which was also submitted to the EPA. EPA comments and AQD responses to EPA comments concerning the original PSD construction permit modeling are contained in the permit record of the original PSD construction permit. The original PSD construction permit modeling was completed following the *Guideline on Air Quality Models* 40

CFR Part 50, Appendix W dated November 6, 2005, and the AQD *Air Dispersion Modeling Guidelines* dated August 2014, with additional guidance from AQD staff. The updated Class II area air dispersion modeling analysis for NO_2, PM_{10}, $PM_{2.5}$, and CO was completed following the updated *Guideline on Air Quality Models* 40 CFR Part 50, Appendix W dated January 17, 2017, and the AQD *Air Dispersion Modeling Guidelines* dated June 2017.

Criteria pollutant modeling was conducted using Lakes Environmental Software, AERMOD View (Version 9.4.0). This software incorporates the AMS/EPA Regulatory Model (AERMOD) Version 16216r, endorsed by EPA. AERMOD is a regulatory steady state plume modeling system. Five years of hourly meteorological data from the state Mesonet site in Bixby, Oklahoma (2006 – 2010) were input into the model. In accordance with AQD modeling guideline Section C.5.d., the EPA-approved AERMOD Model Version 16216r was used for Class II modeling. The Class I significance modeling at 50 km distance from the original PSD permit was not revised. Other models were used as required to complete the original PSD construction permit modeling analyses. CALPUFF Version 5.2.0 was used for Tier 2 significance modeling from the original PSD construction permit. The VISCREEN visibility model Version 13190 was used for Class II visibility screening in the original PSD construction permit.

Class II Area Dispersion Modeling Approach by Pollutant

Class II area modeling was completed to assess project impacts, including the significance analysis, the PSD NAAQS and increment consumption analyses. This section presents the modeling approach by each pollutant considered.

NO_2 Modeling Approach

A full impact modeling analysis was required for 1-hour and annual average NO_2 emissions. SIL, NAAQS, and increment modeling for the project and nearby sources was completed using Tier 3 methods utilizing OLM group ALL for a combined plume analysis. Background concentration data was added for the NAAQS modeling.

EPA provides NO_2 modeling guidance in two memoranda, *Guidance Concerning the Implementation of the 1-hour NAAQS for the Prevention of Significant Deterioration Program* (EPA 2010a) and *Additional Clarification Regarding the Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (EPA 2011), as well as 40 CFR Part 51 Appendix W (EPA 2017). The guidance lists three refinement Tiers for completing 1-hour NO_2 modeling to obtain design concentrations for the short-term standard, the five-year average of the 98th percentile of the annual distribution of daily maximum 1-hour NO_2 concentrations, and also for the maximum annual average NO_2 concentrations over the numbers of years modeled. Tier 1 assumes full conversion of in-stack nitric oxide (NO) emissions to NO_2. Tier 2 applies a default ambient conversion ratio of 0.90 for NO-to-NO_2 conversion. The Tier 3 method is to further refine the modeling analysis and conversion of in-stack NO to ambient NO_2 using the Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limiting Method (OLM), with five years of hourly background ozone data that are concurrent with the meteorological data set. For Tier 3, an initial in-stack conversion of NO to NO_2 is assumed as a ratio to total NO_X emissions (or an in-stack NO_2/NO_X ratio).

Use of the Tier 3 analysis in the original PSD construction permit modeling required approval from AQD and submittal of a protocol to EPA for approval. Comments received by EPA on the Tier 3 modeling protocol were addressed separately in a final response to EPA and are available in the original PSD construction permit record. Due to the updates of Appendix W, the use of OLM in a Tier 3 analysis is considered a regulatory option.

AQD provided the 98th percentile hourly NO_2 and ozone concentration files for 2006-2010, processed on a Seasonal, Hour-of-Day and Day-of-Week basis from the North Tulsa monitor (40-143-1127). For HFTR sources, the EPA default in-stack NO_2/NO_X ratio of 0.5 was used. For nearby facilities, AQD has provided in-stack ratios for various types of combustion sources. AQD has based the in-stack NO_2/NO_X ratios for engines, and heaters/boilers on test data for similar sources. The source data used to develop these in-stack ratios are part of the EPA NO_2 ISR database available on the EPA SCRAM webpage: https://www.epa.gov/scram/nitrogen-dioxidenitrogen-oxide-stack-ratio-isr-database/.

EPA comments and AQD responses to EPA comments concerning in-stack ratios from the original PSD construction permit are available as part of the permit record of the original PSD construction permit. An in-stack NO_2/NO_X ratio of 0.2 was used for all other nearby sources. Tier 3 modeling was completed using the default equilibrium ratio of 0.9.

In-Stack NO_2/NO_X Ratios for Nearby Sources

Source Type	Ratio
LB Engines	0.35
4SRB Engines	0.05
Boilers	0.10
Other Emission Units	0.20

For NO_2, there is a specific control option in AERMOD referred to as the "EPA NAAQS Option," which was used for modeling NO_2 NAAQS compliance. This option is effective for calculating impacts from 1-hour NO_2 as they relate to EPA regulations. A use of this Method applied to this modeling study is the contribution or "MAXDCONT" output files that display source group contributions to concentration totals at individual receptors, paired in time and space, and allowing a cause and contribute analysis to be performed.

PM_{10} and $PM_{2.5}$ Modeling Approach

A full impact modeling analysis was required for 24-hour PM_{10} and $PM_{2.5}$ emissions. SIL, NAAQS, and increment modeling for the project and nearby emission sources was completed following EPA and AQD guidance for these pollutants. Background concentration data was added for the NAAQS modeling analysis.

AERMOD has a specific control option in AERMOD referred to as the "$PM_{2.5}$ EPA NAAQS Option," which was used for modeling $PM_{2.5}$ NAAQS compliance. This option is effective for calculating impacts from 24-hour $PM_{2.5}$, as they relate to EPA regulations. A use of this method applied to this modeling study is the contribution or

"MAXDCONT" output files that display source group contributions to concentration totals at individual receptors, paired in time and space, and allowing a cause and contribute analysis to be performed. For annual project PM_{10} emissions, only a significance analysis was completed. An annual NAAQS or PSD Increment analysis was not required.

The significance emissions rate (SER) for direct $PM_{2.5}$ impact analysis is 10 TPY and the SER for the $PM_{2.5}$ precursors NO_X and/or SO_X are 40 TPY. A $PM_{2.5}$ modeling impact analysis would need to be completed if the NO_X net emission increase exceeds the SER.

As indicated in the original PSD construction permit, as part of their Consent Decree, HFTR West recently completed facility changes with large actual SO_X and NO_X emission reductions. The emission reductions, while mandated for SO_2 and NO_X, are contemporaneous and creditable with the proposed project for secondary $PM_{2.5}$ impacts. Actual SO_X emissions will decrease 1,918 tons/year, based upon the difference between reported 2010-2011 SO_X emissions (2,300 tons/year) and the Projected Actual Emissions (PAE) for SO_X (382 tons/year) after project completion. Actual NO_X emissions will increase 584 tons/year, based upon the difference between reported 2010-2011 NO_X emissions (1,036 tons/year) and the Projected Actual Emissions for NO_X (1,620 tons/year) after project completion. Therefore, overall there will be a large net decrease of combined SO_X and NO_X emissions of 1,334 tons/year. Note that standard EPA inter-pollutant trading ratios value SO_X emission reductions at 2-5 times NO_X emission reductions. No further analysis of secondary $PM_{2.5}$ impacts was required in the original PSD construction permit. EPA comments and AQD responses to EPA comments concerning secondary impacts in the original PSD construction permit are available as part of the permit record of the original PSD construction permit.

The minor changes related to the modified construction permit were not significant enough to revise the historical determination related to secondary formation. Also, the permit application for the modified construction permit were received prior to the end of the transition period related to the updates of Appendix W addressing $PM_{2.5}$ secondary formation.

CO Modeling Approach

For 1-hour and 8-hour average, project CO emissions, only a significance analysis was completed. Full impact modeling was not required because modeled impacts were below the SILs.

Control Parameters

AERMOD was run in the regulatory default mode, including stack-tip downwash and use of elevated terrain algorithms.

The land type in the area must be classified as either urban or rural so that appropriate dispersion parameters may be used with AERMOD. The area within and surrounding the refineries is industrial, and the facility is located in a metropolitan area. To simulate the urban heat island effect, the urban option within AERMOD was selected, assuming the Tulsa population equals 396,466 persons, and with a surface roughness of 1.0 meter.

AERMOD has the capability to account for building downwash produced by airflow over and around structures. Direction-specific building downwash parameters were developed for HFTR sources for input to AERMOD-PRIME using the USEPA Building Profile Input Program, or BPIP-PRIME Model (Version 04274). The BPIP model requires building dimensions as well as stack locations for input. These parameters were determined from site plan maps.

Terrain Considerations

Per AQD guidance, modeling with elevated terrain was conducted. AERMAP (version 11103), was used to assign elevations to stack, buildings, receptors, and hills. Receptor elevations were developed using the National Elevation Dataset (NED) data. The NED data was converted to GeoTIFF format and processed using the Lakes Environmental AERMOD View GUI interface with AERMAP. NED data was processed at 1/3 Arc-Sec resolution; receptor terrain values were interpolated from the nearest NED grid points. Elevations were manually applied to sources and buildings using Google Earth. In the case of where results were sensitive to the elevations at design receptors, interpolated elevations were visually verified using topographical maps and Google Earth, and then refined as needed for accuracy. The base elevation of the facility is approximately 640 feet above mean sea level.

USEPA guidance supports the use of AERSURFACE to process land cover data to determine the surface characteristics (i.e., surface roughness, Bowen ratio, and albedo) for the meteorological measurement site that is used to represent meteorological site conditions. Chapter 2.3.4 of AQD's *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits* also indicates that surface characteristics using AERSURFACE can be used for air permit applications. The GeoTIFF file for Oklahoma containing the land cover data is used as input for AERSURFACE. AQD's modeling guidance document also recommends the following input conditions for running AERSURFACE:

- Center the land cover analysis on the meteorological measurement site.
- Analyze surface roughness within 1 km of measurement site.
- Utilize one sector determining the surface roughness length.
- Temporal resolution of the surface characteristics should be determined on a monthly basis.
- The region does not experience continuous snow cover for most of the winter.
- The Mesonet site is not considered an airport.
- The region is not considered an arid region.
- Utilize the default season assignment (winter=Dec, Jan, Feb; Spring=Mar, Apr, May; Summer=Jun, Jul, Aug; Fall=Sep, Oct, Nov)

Background Concentrations

For the PSD NAAQS analysis, background concentration data was added to impacts from the proposed project and regional sources. AQD provided representative data for NO_2, $PM_{2.5}$, and PM_{10}.

The maximum background concentrations are from the North Tulsa monitoring station 40-143-1127. Values are listed in the table following. For short-term standards, the conservative approach was to add the maximum background concentrations to the NAAQS modeling results. Due to the form of the NO_2 short-term standard, EPA provides other options as detailed in the *Additional Clarification Regarding the Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (EPA 2011) memorandum. The monitor is located approximately 10 km north of the Holly East Refinery and Holly West Refinery. Other nearby facilities in Tulsa including Empire, Covanta, PSO Tulsa, Veolia Energy and Aaon are similarly situated. The winds mainly blow from a southwesterly to southeasterly direction and the aforementioned facilities impact the monitor when the wind blows from that direction. Therefore, full impact modeling when taking into account background concentrations will have the potential for double-counting impacts from those facilities. Because the monitor is located on the north side of the Tulsa metropolitan statistical area, it closely represents the metropolitan area and industrial presence in the Tulsa area.

Background Concentration Data from Permit No. 2012-1062-C (M-1) PSD

Pollutant	Basis	Period of Record[1]	Background Concentration
NO_2	1-hour average daily maximum concentration (98th percentile) averaged over 3 years	2011 - 2013	40.5 ppb (76.2 μg/m^3)
	Maximum annual average	2013	7.87 ppb (14.8 μg/m^3)
$PM_{2.5}$	24-hour average concentration (98th percentile) averaged over 3 years	2011 - 2013	21.7 μg/m^3
	Three-year annual average concentration	2014 - 2016	8.7 μg/m^3
PM_{10}	24-hour average concentration High-fourth-high (H4H)	2011 - 2013	67.0 μg/m^3
CO	1-hour average concentration High-second-high (H2H)	2013	1.60 ppm (1,832 μg/m^3)
	8-hour average concentration High-second-high (H2H)	2013	1.00 ppm (1,145 μg/m^3)

1 – Design values from the most recent monitoring 2014-2016 were reviewed and were determined to be lower than the original design values, except for PM_{10} 24-hour value which was 75 which was μg/m^3. Therefore, the modeled results of all pollutants except PM_{10} will be more conservative than the results using the historical background concentrations. Even taking into account the increase of the background concentration of PM_{10} the modeled impacts are in compliance with the NAAQS.

For further NO_2 modeling refinement, rather than use a single monitored background value, 1-hour average ozone and NO_2 background concentration data from the Tulsa monitor, on an hour-by-hour basis, were used in the model to address the spatial and temporal nature of cumulative NO_2 impacts. These hourly concentration files provided by AQD were calculated based on the five year average of the 98^{th} percentile values from a Seasonal, Hour-of-Day, and Day-of-Week review of the 2006-2010 data.

Good Engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model-predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in OAC 252:100-8-1.5. GEP stack height is defined as the greater of 65 meters or a height established by applying the formula $Hg = H + 1.5L$, where:

Hg = GEP stack height,
H = height of nearby structures, and
L = lesser dimension (height or projected width) of nearby structures,

or by a height demonstrated by a fluid model or a field study that ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

The model utilizes the EPA Building Profile Input Parameters (BPIP) program with the plume rise model enhancements (PRM). BPIP-PRIME determines the effect of building downwash on each plume in calculation of maximum impacts.

Meteorology and Surface Characteristics

AQD supplied five years of AERMET (Version 16216) pre-processed meteorological data (2006-2010) from the state Mesonet site in Bixby, Oklahoma. The Bixby site is located about 20.5 km south-southeast from the HFTR East Refinery and about 23 km south-southeast from the HFTR West Refinery. Depending on the design value modeled, either a single 5-year hourly sequential meteorological data set or five single-year hourly sequential meteorological data sets were utilized. When using AERMET to prepare the meteorological data for AERMOD, the surface characteristics (Albedo, Bowen Ratio, and Surface Roughness Length) for the primary (MESONET) and secondary (NCDC-ISD) meteorological sites were determined using AERSURFACE.

In the original PSD construction permit, the Class I area screening using AERMOD modeling utilized the same hourly sequential meteorological data set utilized in the Class II modeling. The Class I area screening modeling with CALPUFF modeling utilized an ISCST3 meteorological (MET) data file generated with the preprocessor PCRAMMET. For this study, three years of ISCST3-type meteorological data were used in a 'screening' version of CALPUFF. RAMMET View 8.1.0 was used to combine three years of surface and upper air ISCST3 MET data. The data were downloaded from the WebMET website.

Default Site Parameters Modeled In CALPUFF

Parameter	Value
Anemometer Height [m]	6.1
Minimum Monin-Obukhov Length [m]	100.0
Surface Roughness Length (Measurement Site) [m]	1.0
Surface Roughness Length (Application Site) [m]	1.0
Noon-Time Albedo	0.2075
Bowen Ratio	1.625
Anthropogenic Heat Flux [W/m_2]	19.0
Fraction of Net Radiation Absorbed at the Ground	0.27

The surface station at the Oklahoma City Will Rogers World Airport was selected and three years from 1986-1988 were used to compile the CALPUFF ready MET files. The closer MET station in Tulsa was not selected because the corresponding upper air data were not available. Due to the distances involved with the CALPUFF modeling, the surface wind data at Oklahoma City are considered representative of conditions near Tulsa. The anemometer height for this station is equal to 6.1 meters. Other site parameters were automatically selected after choosing "urban" as the land use type. The CALPUFF ready output files were generated assuming no precipitation. This file was then imported into CALPUFF.

Receptor Grid

Class II

A Cartesian receptor grid was developed for Class II air dispersion modeling. The Cartesian receptor grid was defined using UTM NAD83 Zone 15. The receptor grids were designed to capture the maximum pollutant impact locations. Following AQD modeling guidance, a receptor grid was placed with spacing of 100 m out to 1 km, 250 m out to 2.5 km, 500 m out to 5 km, 750 m out to 7.5 km, and 1 km out to the edge of the modeling domain. The edge of the modeling domain was determined to be approximately 20 km from the facility for NO_2, and approximately 12 km from the facility for PM_{10}, $PM_{2.5}$ and CO. Discrete property line receptors were spaced no further than 100 meters apart.

Class I

The Tier I significance modeling for Class I areas from the original PSD construction permit conducted using AERMOD utilized a Polar receptor grid comprised of a circle of receptors with a 50 km radius. There were a total of 360 receptors, spaced along each degree of the circle. The center point of the grid was located at UTM NAD83 Zone 15, coordinates 228430, 4002440. The polar grid was then converted to a series of discrete Cartesian receptors. Only the receptors within the Class I directional ranges were used to determine maximum Class I impacts for the analyses.

For the CALPUFF modeling from the original PSD construction permit, the recommended method of adding ring receptors was not used. Instead, discrete receptors from the four (4) Class I areas were obtained from AQD and imported into the CALPUFF model. Gridded receptors were not included.

Source Input Parameters

The following table lists the facility source parameters used as AERMOD model inputs. The modeling analysis includes emissions from combustion sources including boilers, heaters, gas engines, and flares. Each stack was modeled as a point source. The AERMOD source parameters for modeling include source coordinates in UTM NAD83, base elevation above MSL, stack height, stack gas exit velocity, stack diameter, and stack gas temperature.

HFTR has considered either the option of installing a new hydrogen plant at West Refinery with shutdown of most of the No. 2 Platformer heaters, or an option to retain the No. 2 Platformer. In the PSD Modeling Study, the impacts of only the hydrogen plant scenario is presented, including retaining Plat heaters 3 & 4.

Existing gas engines are a special case in terms of modeling. All are considered "not affected" in terms of the project, but the PDA Compressor, H_2 Recycle Compressor, #2 CT Circ Pump Engine, #3 CT Circ Pump Engine, and #6 CT Circ Pump Engine have been electrified and will have contemporaneous emission reductions with the project. Credit for these emission reductions was only used in the PM_{10} and $PM_{2.5}$ increment modeling analyses. In the new hydrogen plant case, shutdown of No. 2 Platformer heaters 1/2, and 5-7 will provide additional emission reductions. Credit for these emission reductions was only used in the PM_{10} and $PM_{2.5}$ increment modeling analyses.

Each type of modeling impact analysis (SIL, NAAQS, increment) utilized a different set of project emissions rates, calculated in units of gram per second (g/s). For the SIL analysis, project emissions increases were modeled as the difference between the potential-to-emit (PTE) and the baseline actual emissions (BAE), for each pollutant. For the NAAQS analysis, the project PTE, regional source PTE, and background concentration data were included. For the increment analysis, project PTE and regional source PTEor actual emissions from sources installed after the PSD major and minor baseline dates were included. Short-term emission rates were used for each pollutant with 1-hour, 3-hour, 8-hour, or 24-hour averaging time standards, as applicable. Annual emissions rates were used for each pollutant with annual averaging time standards. Updates to Appendix W allow for use of actual emission data for nearby sources in NAAQS analyses.

The SIL analyses required only the modeling of project emission increases, determined by calculating the difference between the 2010-2011 baseline emission rates and the proposed PTE of each affected or modified emission unit. New units constructed for the project have zero baseline emission rates and are modeled with emission increases up to full PTE. Units constructed within 24 months prior to project operation, are assumed have zero project emission increases, with baseline emissions equivalent to PTE. For example, this situation would apply to Boiler 10 at the West Refinery. In AERMOD, project emission increases are typically denoted by "P" at the end of the AERMOD source ID.

The NAAQS analysis required the modeling of PTE, or the maximum amount of an air contaminant that can be emitted by a source. For an existing modified or affected source, the PTE is the sum of the baseline emission rates and the project emission increases. To reduce the number of modeling files and iterations required in AERMOD, each existing emission source was duplicated and co-located to differentiate between the "baseline" emissions for the source, typically denoted by "B" at the of the AERMOD source ID and the project emissions increase from the source, denoted by the "P" at the end of the AERMOD source ID. This separation also serves the purpose of incorporating project emission increases into the full impact analysis to determine that the project does not cause nor contribute to any potential NAAQS exceedance. This allows SIL, NAAQS, and PSD increment to be modeled together in separate source groupings to streamline the modeling work

Analyses was performed on facility and selected nearby regional sources to determine which units were installed before the major and minor source baseline dates. Emissions permitted before the baseline dates were not included in the PSD increment analysis.

HFTR East Refinery & HEP Modeling Source Parameters

	UTM Coordinate		Base	Final	Stack	Exit	Exit
	Easting (m)	Northing (m)	Elevation (m)	Height (m)	Diameter (m)	Velocity (m/s)	Temp (^oK)
Project Units - New							
CCR Helper Heater (new)	229947	4000693	193	22.9	0.76	9.53	478
NHDS Helper Heater (new)	229670	4000663	192	22.9	0.46	10.59	478
DHTU Helper Heater (new)	229945	4000602	195	22.9	1.00	11.07	478
ROSE Heater (new)	229928	4000641	195	22.9	1.00	9.30	478
Project Units - Affected or Modified							
DHTU Charge Heater 1H-101	229947	4000617	195	42.7	1.46	10.10	583
CCR Charge Heater 10H-101, #2-1 Interheater 10H-102, #2-2 Interheater 10H-103	229950	4000673	195	37.8	1.77	19.86	561
CCR Stabilizer Reboiler 10H-104 & Naphtha Splitter Reboiler	229951	4000700	195	37.8	1.37	21.00	533
CCR Interheater #1 10H-113	229971	4000688	195	38.1	2.53	5.24	466
Boiler #1	229910	4001435	193	18.2	1.83	13.63	422
Boiler #2	229918	4001435	193	18.2	1.83	13.63	422
Boiler #3	229936	4001434	193	18.2	1.83	13.63	422
Boiler #4	229945	4001434	193	18.2	1.83	13.63	422
Sulfur Recovery Unit/Tail Gas Treating Unit (SRU/TGTU) #1	229823	4000611	192	61.0	0.61	5.88	501
Sulfur Recovery Unit/Tail Gas Treating Unit (SRU/TGTU) #2	229762	4000608	192	30.8	0.76	7.65	341

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (°K)
	Easting (m)	Northing (m)					
NHDS Charge Heater 02H-001	229664	4000659	192	30.5	1.13	9.84	693
NHDS Stripper Reboiler 02H-002	229658	4000653	192	29.3	1.13	12.74	791
Vacuum Tower Heater	229956	4001097	194	53.3	3.51	1.60	450
CDU Atmospheric Tower Heater	229956	4001088	194	30.5	3.0	5.42	450
FCCU Charge Heater B-2	229945	4000871	194	41.1	1.77	14.41	625
FCCU Regenerator	229945	4000861	194	46.0	1.52	15.52	333
Unifiner Charge Heater H-1	229938	4000775	193	14.6	1.16	10.72	783
Scanfiner Charge Heater 12H-101	229954	4001001	193	13.7	1.07	7.95	585
VCU Terminal Loading	229352	4000605	193	13.7	2.44	3.08	1,033

HFTR West Refinery Modeling Source Parameters

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (°K)
	Easting (m)	Northing (m)					
Project Units - New							
Modified PDA to ROSE, new heater	228750	4003806	195.1	22.9	1.00	16.83	478
Hydrogen Plant Reformer Heater	228143	4004066	195.0	22.9	1.52	13.30	533
Project Units - Affected or Modified							
#7 Boiler	228660	4003895	195.1	18.3	1.52	12.13	430
#8 Boiler	228660	4003903	195.1	18.3	1.52	13.57	481

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (^oK)
	Easting (m)	Northing (m)					
#9 Boiler	228658	4003859	195.1	24.4	1.52	11.37	403
#10 Boiler	228588	4003843	195.1	15.2	1.45	21.83	459
CDU Atmospheric Tower Heater - North Stack	228262	4003837	194.3	41.2	2.26	7.17	522
CDU Atmospheric Tower Heater - South Stack	228261	4003822	194.3	41.2	2.26	7.11	518
CDU #1 & #2 Vacuum Tower Heaters	228279	4003823	194.5	38.1	2.26	7.59	718
EG-5747	228750	4003806	195.1	6.71	0.15	13.20	589
Unifiner Charge Heater	228239	4003969	194.6	20.1	1.37	4.89	574
Unifiner Stripper Reboiler Heater	228239	4003982	194.3	23.5	1.52	5.84	522
C-2719	228288	4003961	194.5	7.62	0.21	7.26	547
No. 2 Platformer Charge Heater (PH-1/2)	228247	4004021	193.9	27.7	2.13	7.36	884
No. 2 Platformer Charge Heater (PH-3)	228238	4003989	194.2	15.2	1.37	5.67	673
No. 2 Platformer Charge Heater (PH-4)	228237	4003995	194.2	15.2	1.52	3.83	455
No. 2 Platformer Charge Heater (PH-5)	228262	4004030	193.9	27.4	2.13	4.59	732
No. 2 Platformer Charge Heater (PH-6)	228251	4004029	193.9	25.9	1.52	5.06	769
No. 2 Platformer Charge Heater (PH-7)	228246	4004013	193.9	30.8	1.13	9.13	1,039
Coker Drum Charge Heater (B-1)	228528	4004114	195.1	34.1	1.68	5.79	621
Coker Preheater (H-3)	228524	4004106	195.4	27.7	1.22	5.26	555
LEU Raffinate Mix Heater (H101)	229176	4003722	195.1	27.4	0.91	6.36	543

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (^oK)
	Easting (m)	Northing (m)					
LEU Extract Mix Heater (H102) North Stack	229185	4003728	195.1	38.1	1.62	5.98	558
LEU Extract Mix Heater (H102) South Stack	229185	4003718	195.2	38.1	1.62	6.03	563
LEU Hydrotreater Charge Heater (H201)	229176	4003712	195.1	30.5	1.62	2.32	619
MEK - Wax Free Oil Heater	229194	4003727	195.2	34.1	1.83	5.06	478
MEK - Soft Wax Heater (H-2)	229202	4003723	195.2	19.0	1.07	9.08	483
EG-5579	228851	4003794	195.0	7.62	0.31	2.65	616
EG-5156	228578	4004020	195.0	7.62	0.31	0.001	644
EG-5152	228605	4003885	195.0	5.49	0.31	0.001	616
EG-5154	228617	4003889	195.0	5.49	0.15	14.33	616

HFTR emissions permitted before the applicable major source baseline dates were excluded from increment analyses. In addition to the new sources for this project, the following sources were included in the increment review.

	NO_2	PM_{10}	$PM_{2.5}$
HFTR East Refinery			
Naphtha Splitter Reboiler	+2011	+2011	
CCR Interheater #1 (10H-113)	+2005	+2005	
Sulfur Recovery Unit (SRU) #2	+2006	+2006	
NHDS Charge Heater	+2006	+2006	
NHDS Reboiler Heater	+2006	+2006	
Scanfiner Charge Heater	+2004	+2004	
CDU Atmospheric Tower Heater			+2014
DHTU			+2017
FCCU			+2017
HEP			
Loading racks / VCU	+2012	+2012	
HFTR West Refinery			
#3 Boiler	-2014	-2014	-2014
#4 Boiler	-2014	-2014	-2014
#10 Boiler	+2014	+2014	+2014
PDA Propane Compressor	-2013	-2013	-2013
Unifiner H2 Recycle Compressor	-2013	-2013	-2013
No. 2 Platformer Charge Heater (PH-4)	+2014	+2014	+2014
No. 2 Platformer Charge Heater (PH-5)	+1990	+1990	
Coker Drum Charge Heater (B-1)	+1992	+1992	
Coker Preheater (H-3)	+1995	+1995	
#2 CT Circ Pump Engine	-2013	-2013	-2013
#3 CT Circ Pump Engine	-2014	-2014	-2014
#6 CT Circ Pump Engine	-2014	-2014	-2014
#6 CT Spray Pump Engine	-2013	-2013	-2013

Reductions in actual emissions are credited for shutdown sources. Only the proposed new sources and associated emission increases at existing sources are included in the increment analysis for $PM_{2.5}$.

Regional sources excluded from increment analysis include PSO Tulsa, Empire Castings, and all but the most recently permitted turbine at Veolia (permitted 2007). Increment analysis must identify impacts of actual emissions, but for screening the higher potential emissions were used except where actual operating data was provided by AQD.

Urban/Rural Classification

Section 8.2.3 of the GAQM (2005) provides the basis for determining the urban/rural status of a source. For most applications, the land use procedure described in Section 8.2.3(c) is sufficient for determining the urban/rural status. However, there may be sources located within an urban area, but located close enough to a body of water to result in a predominantly rural classification. In those cases, the population density procedure may be more appropriate. Only the following land use procedure is used to assess the urban/rural status of the source.

- Classify the land use within the total area, A_o, circumscribed by a 3-km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multifamily compact residential) account for 50 percent or more of A_o, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on visual inspection of the USGS 7.5-minute topographic map of the project site location, it was conservatively concluded that over 50 percent of the area surrounding the project may be classified as urban. Accordingly, the urban dispersion modeling option is used in the AERMOD PRIME model.

Regional Inventory Emissions and Source Parameters

AQD provided an inventory of source parameters and emission rates for each pollutant for nearby sources in the Tulsa region. The source databases reviewed including all sources within 100 km of the facility and those sources excluded from the modeling analysis is available for review upon request. Stack locations, source parameters and emission rates were provided for modeling. The stack location coordinates were independently researched for inconsistencies with the site address prior to use in the modeling. Where information differed from the AQD database, corrections were entered to the inventory. Google Earth was used to corroborate or correct regional source facility coordinates provided in the ARIES file.

All regional sources within 10 km were included in the analysis while all regional sources outside of 50 km were excluded from the analysis. The AQD narrowed the list of existing nearby sources required to be included in the NAAQS and increment modeling analyses to only those that would be expected to have a significant concentration gradient within the modeling domain for those sources outside of 10 km, but within 50 km. The facility eliminated two sources from the list provided by AQD using the "10 D Rule," which eliminates sources from the modeling review when the emissions (TPY) are less than 10 times the distance (in kilometers) from the modeled facility: "BIZJET INTL" and "ST FRANCIS HOSP". Based on the updates to Appendix W, these sources would be considered other sources that are represented by the background concentration. EPA comments and AQD responses to EPA comments concerning sources excluded in the original PSD construction permit modeling analyses are available as part of the permit record of the original PSD construction permit. A review of nearby/other sources constructed/modified since issuance of the original PSD construction permit did not yield any additional sources with significant impacts within the modeling domain.

Regional sources are only included in the Class II full impact modeling analyses. The regional source emission rates are permitted, potential-to-emit values for short-term modeled rates, unless otherwise noted. AQD provided operating factors for some units to be used on annual emission rates. The operating factors account for the assumption that equipment does not operate 8,760 hours per year. With AQD approval, some units were allowed to be "excluded as intermittent" from 1-hr short-term impacts in the modeling study.

Significance Analysis

Dispersion modeling analysis usually involves two distinct phases; a preliminary analysis and a full impact analysis. The preliminary analysis models only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed project. Specifically, the preliminary analysis:

- determines whether the applicant can forego further air quality analyses for a particular pollutant;
- may allow the applicant to be exempted from the ambient monitoring data requirements; and
- is used to define the impact area within which a full impact analysis must be carried out.

In general, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants. The full impact analysis is not required for a particular pollutant when emissions of that pollutant would not increase ambient concentrations by more than the applicable significant impact level (SIL).

For the pollutants that exceeded the SERs, NO_2, $PM_{2.5}$, PM_{10} and CO, preliminary modeling was completed for comparison to the SIL. For pollutants with maximum off-site ambient concentrations less than the applicable SIL, no further impact assessment is required. If impacts are greater than the SIL, then a full impact modeling analysis is required, including a NAAQS modeling analysis (Class II areas) and a PSD increment consumption analysis (Class I and Class II areas). Air quality modeling for ozone impacts is not required because VOC emission increases from the project will not exceed 100 TPY.

Using EPA's May 2014 "Guidance for $PM_{2.5}$ Permit Modeling," a full impact analysis for $PM_{2.5}$ is not required if: (1) the difference between the $PM_{2.5}$ background concentration and the $PM_{2.5}$ NAAQS is greater than the $PM_{2.5}$ significance impact level; and (2) the modeled impacts of $PM_{2.5}$ from the project would not increase ambient concentrations by more than the $PM_{2.5}$ significant impact level (SIL). The same analysis was completed for NO_2, CO and PM_{10}. As demonstrated by the following table, a full impact analysis is not required for CO or annual PM_{10}.

The full impact analysis considers emissions from existing sources, as well as the emission increases associated with the project, to comply with NAAQS and PSD increment consumption analyses. This required the addition of background concentration levels and regional source emissions, as provided by AQD.

Pollutant	Averaging Period	Max Project Impact $\mu g/m^3$	SIL $\mu g/m^3$	Full Impact Analysis Required?
NO_2	1-hr	109.2	7.5	Yes
	Annual	6.7	1	Yes
PM_{10}	24-hr	5.7	5	Yes
	Annual	0.7	1	No
$PM_{2.5}$	24-hr	4.5	1.2	Yes
	Annual	0.7	0.3	Yes
CO	1-hr	205	2,000	No
	8-hr	104	500	No

Full Impact Analyses

The next step was to perform a full impact analysis. The full impact analysis considers emissions from existing sources, as well as the emission increases associated with the project, to comply with NAAQS and increment consumption analyses. A Class II full impact analysis was required for NO_2, $PM_{2.5}$, and PM_{10} because the SILs were exceeded. The full impact analysis required more refined modeling to compare impacts to the Class II National Ambient Air Quality Standards (NAAQS). For the NAAQS analysis, modeling results for the combined criteria pollutant impacts from Holly East, Holly West, HEP and regional sources were added to corresponding background concentrations.

Modeling results for NAAQS and Class II increment analyses are presented following. MAXDCONT files were used to assist in demonstrating compliance with the 1-hour NO_2 and $PM_{2.5}$ 24-hour NAAQS. The MAXDCONT files were used to pair impacts in time in space at receptors to demonstrate that project impacts are not significant at the occurrence of a NAAQS or increment exceedance. The results are presented in the corresponding tables following.

Compliance with the NAAQS is demonstrated when: 1) modeled impacts are below the NAAQS standards (for example on the Holly East Refinery and Holly West Refinery property lines) and, 2) modeled impacts from the proposed Project emission increases are not significant at any locations where the NAAQS is exceeded (for example by a regional source).

For purposes of NAAQS compliance, where background concentrations are added to modeled impacts, AQD provided guidance on minimizing double counting due to the nearby facility emission impacts on the background monitoring data. For sources impacting the monitor, modeled emission rates were reduced by a factor representing actual emissions times the source operating factor. EPA comments and AQD responses to EPA comments concerning the AQD guidance related to double counting of source impacts in the original PSD construction permit modeling analyses are available as part of the permit record of the original PSD construction permit. Updates to Appendix W allow for use of actual emissions rather than potential emissions for nearby sources, for reducing the number of nearby sources to be explicitly modeled, and identifying the majority of sources as other sources that are represented by air quality monitoring data. These policies are considered more conservative than how the nearby sources to be explicitly included in the modeling for the original PSD construction permit.

The modeling results for 1-hour and annual NO_2 are presented here. There were 43 potential modeled violations of the NAAQS confined to four receptors within the modeling domain out to the highest 29th High impact. The maximum 1-hour NO_2 NAAQS impacts for the four receptors, paired with the corresponding project contribution in time and space, is shown in the following table. Each of the potential modeled violations were examined and the project did not have a significant contribution at any of them. The modeled annual NO_2 maximum impact did not exceed the NAAQS at any receptor and did not require further analysis.

NO_2 Max NAAQS & Project Contribution **NO_2 Max NAAQS & Project Contribution**

Pollutant	Averaging Period	NAAQS µg/m³	Max Impact µg/m³	E UTM m	N UTM m	Project Contribution[1] µg/m³
NO_2	1-hour	188	218.2	247430	4009440	0.00
			195.4	230330	4005040	2.70
			189.9	230230	4005040	0.06
			190.7	230330	4005140	0.81
	Annual	100	71.6			

[1] 1-hour NAAQS and project contribution paired in time & space using MAXDCONT.

PM_{10} full impact modeling was performed to demonstrate compliance with the 24-hour NAAQS standard, and the results are in the following table. Even with the 8 µg/m³ increase in the design value from the 2011-2013 to the 2014-2016 monitoring data, the modeled impacts are in compliance with the NAAQS.

PM_{10} NAAQS Modeling Results

Pollutant	Averaging Period	NAAQS µg/m³	Impact µg/m³	NAAQS Exceeded?
PM_{10}	24-hour	150	123	No

$PM_{2.5}$ full impact modeling was performed to demonstrate compliance with the 24-hour and annual NAAQS standards. There were 603 potential modeled violations of the $PM_{2.5}$ 24-hour NAAQS within the modeling domain compared to 26 receptors. There were 28 potential modeled violations of $PM_{2.5}$ Annual NAAQS. The maximum NAAQS impact of these receptors, paired with the corresponding project contribution in time and space, is presented following. The project was not significant at any of the receptors where a potential modeled violation occurred.

$PM_{2.5}$ Max NAAQS & Project Contribution

Pollutant	Averaging Period	NAAQS µg/m³	Max Impact µg/m³	E UTM m	N UTM m	Project Contribution[1] µg/m³
$PM_{2.5}$	24-hour	35	38.37	228330	4002340	0.59
			37.43	228330	4002440	0.73

$PM_{2.5}$ Max NAAQS & Project Contribution

Pollutant	Averaging Period	NAAQS µg/m³	Max Impact µg/m³	E UTM m	N UTM m	Project Contribution[1] µg/m³
			37.00	228430	4002140	0.29
			42.03	228430	4002240	0.29
			46.69	228430	4002340	0.62
			40.97	228430	4002440	0.60
			36.28	228430	4002540	0.31
			35.69	228530	4002140	0.38
			41.82	228530	4002240	0.56
			44.99	228530	4002340	0.45
			43.24	228530	4002440	0.11
			38.55	228530	4002540	0.02
			35.18	228630	4002240	0.39
			36.01	228630	4002340	0.34
			41.85	228030	4005040	0.38
			41.25	228030	4005140	0.49
			39.01	236430	4007940	0.06
			38.87	224430	3995940	0.00
			43.08	224430	3995440	0.25
			37.00	222430	4003440	0.01
			57.87	238430	4004440	0.02
			41.27	220430	3990440	0.00
			60.08	220430	3989440	0.00
			50.85	220430	3988440	0.09
	Annual	12	12.15	228430	4002340	0.26
			12.40	228430	4002440	0.26
			12.01	228430	4002540	0.26
			12.54	228530	4002440	0.27
			12.99	228030	4005140	0.24
			15.16	236430	4007940	0.03
			16.17	224430	3995940	0.05
			16.74	224430	3995440	0.05
			17.74	238430	4004440	0.03
			12.15	220430	3991440	0.02
			14.19	220430	3990440	0.02
			17.54	220430	3989440	0.02
			14.20	220430	3988440	0.02
			12.32	220430	3987440	0.02

[1] - 24-hour NAAQS and project contribution paired in time & space using MAXDCONT.

For the $PM_{2.5}$ 24-hour NAAQS there were two receptors where the combined impacts from HFTR East Refinery, HFTR West Refinery, and HEP facilities exceeded the SIL and the $PM_{2.5}$ 24-hour NAAQS. These receptors were within the Empire Castings and AAON facility fencelines and the impacts were due primarily to emissions from these facilities. Approval was granted by AQD to subtract impacts from these sources from the total impacts at these receptors within the boundaries of the individual facilities to determine NAAQS compliance. After subtracting the contribution of Empire Castings and AAON within the airspace of the respective facility boundaries (per EPA memo "Ambient Air", October 17, 1989), there were no exceedances of the NAAQS as indicated below.

Adjusted Annual $PM_{2.5}$ Impact Analysis Within Empire Fencelines[1]

Receptor Within Empire Fenceline		NAAQS (µg/m³)	Modeled Impact (µg/m³)	Empire Contribution (µg/m³)	Corrected Impact[1] (µg/m³)	NAAQS Exceeded?
X Coord.	Y Coord.					
228030	4005140	12	12.99	2.92	10.07	NO

[1] - The Annual $PM_{2.5}$ impacts from Empire Castings were subtracted from total impact within the facility's fenceline using source groupings from the MAXDCONT analysis.

Adjusted Annual $PM_{2.5}$ Impact Analysis Within AAON Fencelines[1]

Receptor Within AAON Fenceline		NAAQS (µg/m³)	Modeled Impact (µg/m³)	AAON Contribution (µg/m³)	Corrected Impact[1] (µg/m³)	NAAQS Exceeded?
X Coord.	Y Coord.					
228430	4002340	12	12.15	2.10	10.05	NO
228430	4002440		12.40	2.37	10.03	NO
228430	4002540		12.01	2.00	10.01	NO
228530	4002440		12.54	2.51	10.03	NO

[1] - The Annual $PM_{2.5}$ impacts from AAON were subtracted from total impact within the facility's fenceline using source groupings from the MAXDCONT analysis.

There were five receptors where the combined impacts from HFTR East Refinery, HFTR West Refinery, and HEP facilities exceeded the SIL and the $PM_{2.5}$ Annual NAAQS. However, since the project impacts were below the SIL no further analyses were conducted.

PSD Increment Consumption

To complete the PSD increment consumption analysis, the criteria pollutant emissions increase above the PSD baseline level for each emission source considered in the study must be modeled. The increments are more stringent for Class I areas such as National Parks and wilderness areas, than for Class II areas, such as the area near the site. A modeling analysis using potential emissions is usually conducted and if compliance is unable to be demonstrated than a modeling analysis using actual emissions is conducted.

Not all emission sources are assumed to be increment-consuming. For each pollutant, the PSD increment analysis includes only the project emission increases for all units built before the applicable major and minor source baseline dates and PTE or actual emissions for all sources built after the applicable major and minor source baseline dates.

The major source baseline date for NO_2 is February 8, 1988. The major source baseline date for PM_{10} is January 1, 1975. The major source baseline date for $PM_{2.5}$ is October 20, 2010. All emission increases and decreases at major sources after the major source baseline dates must be included in the regional increment consumption analysis. The Tulsa County NO_2 minor source baseline date was triggered in Air Quality Control Region (AQCR) 186, including Tulsa County, on June 23, 1989. The PM_{10} minor source baseline date was triggered in Tulsa County on September 9, 1982, and the remainder of AQCR 186 on August 25, 1982. Minor source emission changes after the minor source baseline dates must be included in the regional increment consumption analysis. The $PM_{2.5}$ minor source baseline was triggered by the HFTR and HEP PSD application on October 14, 2014.

Compliance with the PSD increment consumption analysis is shown when: 1) total increment consumption after the baseline date does not exceed the increments and 2) impacts from proposed project emission increases are not significant at any locations where the increment thresholds are exceeded (i.e. by a regional source).

PSD increment modeling results for annual NO_2 increment are presented in the following table. The maximum impact does not exceed the increment. Therefore, no further modeling was required.

NO_2 Class II Increment Modeling Results

Pollutant	Averaging Period	Increment $\mu g/m^3$	Max Impact $\mu g/m^3$	Increment Exceeded?
NO_2	Annual	25	15.4	No

PSD increment modeling results for 24-hour PM_{10} increment are presented below. The modeling submitted by the applicant predicted a potential modeled violation of the PM_{10} 24-hour increment. There were fourteen receptor locations where predicted potential modeled violations of the Increment occurred. The maximum 24-hour PM_{10} Increment impacts for the fourteen receptors, paired with the maximum impact from the project, are shown in the following table. Using the MAXDCONT analysis, it was determined that the project does not have a significant impact (5 $\mu g/m^3$) at any of the potential modeled violations. A PM_{10} annual PSD increment study was not required because the SIL was not exceeded.

PM_{10} Increment Results For Year With Maximum & Project Contributions

Pollutant	Averaging Period	Increment µg/m³	Max Impact µg/m³	E UTM m	N UTM M	Max Project Contribution µg/m³	Year
PM_{10}	24-hour	30	56.62	220430	3988440	0.22	2009
			54.24	220430	3989440	0.23	2009
			52.32	224430	3995440	0.38	2009
			34.19	224430	3995940	0.37	2009
			42.55	228430	4002240	1.31	2010
			41.24	228430	4002340	1.39	2009
			31.11	228430	4002440	1.36	2008
			44.57	228530	4002240	1.21	2007
			31.49	228530	4002340	1.39	2008
			34.43	228530	4002440	1.48	2007
			30.25	228530	4002540	0.98	2007
			30.84	228630	4002240	1.13	2010
			31.43	228630	4002340	1.06	2009
			41.79	238430	4004440	0.29	2009
			49.88	238430	4004440	0.25	0.29

PSD increment modeling results for 24-hour and annual $PM_{2.5}$ increments are presented below. The increment was not exceeded at any receptor.

$PM_{2.5}$ Class II Increment Modeling Results

Pollutant	Averaging Period	Increment µg/m³	Max Impact µg/m³	Increment Exceeded?
$PM_{2.5}$	24-hour	9	5.6	No
	Annual	4	0.7	No

PSD Monitoring Exemption Thresholds

On a case-by-case basis, AQD has the authority to require pre-construction air quality monitoring for background concentration data, unless modeled impacts from project emission increases, or existing ambient concentrations, are below the PSD monitoring exemption thresholds. Modeling was completed for comparison to the exemption thresholds as shown in the table below. While some of the monitoring exemption thresholds are exceeded by modeled impacts, representative background concentration data are available for all pollutants and averaging periods from the North Tulsa monitor (40-143-1127). Therefore, pre-construction monitoring is not needed.

Pollutant	Averaging Period	Monitoring Exemption Threshold $\mu g/m^3$	Maximum Impacts $\mu g/m^3$	Threshold Exceeded?
NO_2	Annual	14	6.7	No
PM_{10}	24-hour	10	5.7	No
CO	8-hour	575	104	No

Ozone Impacts Assessment

Under OAC 252:100-35(c), an increase in NO_X or VOC of 100 TPY triggers an ambient impact analysis for ozone, including gathering of ambient air quality data. That ambient monitoring is already being performed in the Tulsa metro area, therefore, that requirement is adequately fulfilled. The changes related to this modification were not significant enough to revise the previous determination and the discussion is included for historical purposes. EPA comments and AQD responses to EPA comments concerning the ozone impact assessment in the original PSD construction permit are available as part of the permit record of the original PSD construction permit. Updates to Appendix W and EPA guidance has addressed single source ozone determinations using modeled emission rates for precursors (MERPS). However, this permit was submitted during the transition period for these updates.

The calculated NO_X emissions increase of 544 TPY result mostly from increased utilization of existing units. Added NO_X emissions from 376 MMBTUH of additional heaters and one modification of capacity would be 49 TPY. The net increase does not take into account significant reductions in both NO_X and VOC required by the recent facility Consent Decree.

The area will have a rather large decrease in actual NO_X emissions from implementation of Consent Decree requirements. These projects include retirement of Boilers 1 through 4, installation of two flare gas recovery units (FGRU) which decreased the amount of gas being flared, and emissions reductions at the Fluid Catalytic Cracking Unit (FCCU). The reduction in actual emissions from those activities was 1,001 TPY NO_X. While the consent decree explicitly states that netting analyses shall not include emission reductions achieved through the consent decrees, it does not specifically address ambient impact analyses. It was determined in the original permit that reductions in ambient impacts should be considered in the evaluation of actual changes in ozone impacts for the facility, because impact analyses do not force technology nor require controls but instead inform the community of the likely changes in ambient pollutant concentrations that may result from the facility. Also, the changes in ambient impacts due to the emissions reductions will be observed in the monitoring data.

Ozone analyses typically use a relative response approach to impact assessment. A baseline inventory is modeled to provide an initial value. The inventory is then modified to reflect the future projected actual emissions and modeled again. The difference in projected ozone values is added or subtracted from local monitors to provide a rough assessment of ambient ozone impacts. In evaluating projected ambient ozone concentrations, inclusion of the federally contemporaneous reductions that have occurred at the facility is fully consistent with the logic that requires contemporaneous increases and decreases to be considered in project evaluations in the first place. It provides a more accurate depiction of facility-wide impacts over time. In this instance, reductions in NO_X emissions are well in excess of increases.

It is concluded that the proposed expansion will not have a deleterious effect on ambient ozone concentrations in the Tulsa area. The design value has decreased significantly over the last five years (2013-2017) at the Tulsa monitor (40-143-1127) from 80 ppb to 64 ppb.

SECTION IX. OTHER PSD ANALYSES

A. Evaluation of Class I Area Impacts

Class I areas are provided special protection under PSD by Air Quality Related Values (AQRVs) defined and enforced by the Federal Land Manager (FLM). The FLM may recommend against issuance of a PSD permit if a source adversely impacts the AQRVs. Potential AQRV impacts are screened per the FLM guidance in *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010)* (NPS 2010). For sources located more than 50 km from a Class I area and passing screening under the 10D Rule there is a presumptive No Adverse Impact. Modeling may still be required to demonstrate compliance with EPA Class increment thresholds.

Under the 10D Rule, the equation Q/D<10 is applied, where:

> Q is equal to the sum of the emission increases of NO_X and PM_{10} that result from the proposed project (in TPY).
>
> D is the distance from the source to the Class I Area (in km).

The maximum project emission increases based upon maximum hourly emissions estimates, $NO_X + PM_{10} = 656$ TPY, were compared to the minimum Class I distance, 230 km. The Q/D value (2.9) does not exceed 10. Therefore, a refined Class I area analysis evaluating impacts to the AQRVs, including deposition and visibility, is not required. Note that this analysis does not account for the large, contemporaneous reductions in actual NO_X and SO_2 emissions that have recently occurred at the HFTR West refinery.

This section addresses the Class I significance modeling analysis required for the PSD Modeling Study. AERMOD was used to determine compliance with the Class I significance thresholds. EPA requires a screening analysis for Class I SILs if a facility is within 300 km of a Class I area. This analysis is a tiered analysis to reduce the burden on the applicant. For Tier I, facilities can use AERMOD as a screening model to determine impacts from the project emission increases out to 50 km from the facility. In the original PSD construction permit a screening analysis using CALPUFF was conducted for $PM_{2.5}$. However, due to a correction of the SIL the screening analyses using AERMOD have demonstrated that the facility will not significantly affect any of the Class I Areas.

Location of Class I Areas within 300 Kilometers

The nearest Class I areas within 300 km of the project site are the Caney Creek Wilderness (250 km), the Hercules-Glades Wilderness (280 km), the Upper Buffalo Wilderness (230 km), and the Wichita Mountains Wilderness (280 km). The Class I area details are summarized following.

Class I Areas Within 300 km of HFTR Facilities

Class I Area	State	Distance (km) & Direction From HFTR
Caney Creek	Arkansas	250 km East-Southeast (137° - 140°)
Hercules-Glades Wilderness Area	Missouri	280 km Northeast (77° - 78°)
Upper Buffalo Wilderness Area	Arkansas	230 km East (97° - 99°)
Wichita Mountains Wildlife Refuge	Oklahoma	280 km Southwest (239° - 241°)

The Class I area impact screening analysis requires modeling of the project's impacts at 50 km to determine if the project's impacts exceed the Class I SILs. The maxima were obtained in the angular direction of the Class I areas. If impacts are less than the SILs, no further analysis is necessary; if they exceed the SILs, CALPUFF modeling is used to determine project impacts.

Model Results for Class I Tier I Significant Impact Analysis

Pollutant	Averaging Period	Significant Impact Level ($\mu g/m^3$)	Max Class I Impacts ($\mu g/m^3$)	Exceeded in Direction of Class I Area?
NO_2	Annual	0.1	0.04	No
PM_{10}	24-hour	0.3	0.11	No
	Annual	0.2	0.01	No
$PM_{2.5}$	24-hour[1]	0.27	0.11	No
	Annual[1]	0.05	0.01	No

[1] - These values were updated to reflect the current EPA guidance.

B. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, and Visibility

Commercial, Residential, and Industrial Growth Analysis

The intent of a growth analysis is to assess air quality impacts due to residential and commercial growth due directly to a proposed modification or new construction. If such activity requires a large new work force, such growth would result due to the influx of families associated with the workforce.

An increase in the workforce will be observed during construction, but the increase in permanent employees is expected to be small. Because the project is located in an urban setting, it is likely that the majority of any construction workers or new permanent employees will be hired locally and that the true number of relocating families will be quite small. In consideration of these issues, it is estimated that air quality impacts associated with growth will be minimal (if detectable at all).

Soils & Vegetation Analyses

The effect of the proposed project emissions on local soils and vegetation were addressed through comparison of modeled impacts to the secondary NAAQS for NO_2, $PM_{2.5}$, and PM_{10} shown in in the following table. There is no secondary standard for CO. The secondary NAAQS were established to protect general public welfare and the environment. The secondary NAAQS for NO_2, $PM_{2.5}$, and PM_{10} are either identical to or less stringent than the primary NAAQS for the same averaging interval.

Accordingly, compliance with primary NAAQS shown earlier in this report, by modeling of either SIL or NAAQS, demonstrates compliance with secondary NAAQS.

Secondary NAAQS Thresholds

Pollutant	Modeling Design Basis	NAAQS Threshold ($\mu g/m^3$)
NO_2	Maximum annual average over each of 5 years modeled	100 (53 ppb)
$PM_{2.5}$	24-hour average concentration 98th percentile average at each receptor over 5 years modeled	35
	Annual average, averaged over 5 years	15
PM_{10}	24-hour average concentration high-6th high (H6H) at each receptor over 5 years modeled	150

In general, modeled impacts below the secondary NAAQS indicate no adverse impacts on soils and vegetation. No sensitive aspects of the soil and vegetation in this area have been identified. Since modeling results demonstrate compliance with secondary standards it is anticipated that the potential impacts to the soil and vegetation will be negligible.

Based upon the results, it is concluded that the construction of the proposed project will not have a significant adverse impact on the surrounding soil and vegetation.

Visibility Impairment Analysis

The Class II visibility analysis requirements and results are presented in this section. Class II visibility impacts from the project were assessed with the VISCREEN model. AQD guidance was used in conjunction with EPA's *Workbook for Plume Visual Impact Screening and Analysis* (EPA 1992) to assess visibility impacts. Figure 9 from EPA's *Workbook* demonstrates that the background visual range to be used in the modeling for Tulsa, Oklahoma is 40 km.

AQD's guidance for determining visibility impacts in a Class II area allows the screening levels to be three times the Class I screening levels. This means that the relative sensitivity, ΔE, value of 6.0 and an absolute green contrast value of 0.15 were used.

A range of source-observer distances was evaluated, and the results were compared to the appropriate screening thresholds. This analysis included near-field locations within the Class II area, especially at any sensitive areas within 40 km. No areas within that distance were identified at this time. As a result, 40 km was the distance used for the source to observer and source to nearest Class I area boundary.

Modeling Results for Visibility Impacts

Background	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Critical	Plume	Critical	Plume
Sky	10	55	35.8	114	6	1.654	0.15	0.001
Sky	140	55	35.8	114	6	0.599	0.15	-0.010
Terrain	10	0	1.0	168	6	0.889	0.15	0.009
Terrain	140	0	1.0	168	6	0.263	0.15	0.009

None of the critical levels, or thresholds, were exceeded by the plume, or impacts at a distance of 40 km.

SECTION X. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
This subchapter sets forth permit application fees and the substantive requirements for operating permits required by 40 CFR Part 70 sources. Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the permit applications, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emissions event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies a PM emission limitation of 0.60 lbs/MMBtu for all equipment at this facility with a heat input rating of 10 Million BTU per hour (MMBTUH) or less and sets a most restrictive rating of 0.10 lb/MMBTU for the largest equipment. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the fuel-burning equipment listed in EUGs 1, 2, 3, 4, 5, 6, 36, 37, 38, 39, and 40 is subject to the requirements of this subchapter. Gas-fired fuel-burning equipment at the facility burns either RFG or commercial grade natural gas (or its equal). RFG is a mixture of various process unit light gases that contain hydrogen (non-particle emitting) and methane through butane light hydrocarbons. RFG is a dry gas, free of liquid particles due to liquid knockout collection drums prior to final fuel end use. Dry gas is recognized by EPA to be at least as clean burning, as to

particulates, as commercial grade natural gas. Since AP-42 has no distinct factor for dry gas mixtures the following demonstrations are based on the natural gas (methane) factors. Table 1.4-2 of AP-42 lists the total PM emission factor for equipment burning natural gas to be 7.6 lbs/10^6ft^3. If we make the conservatively high assumption that PM emissions are related only to volume and that heat content has no effect, then the gas with the highest PM emission in units of pounds per MMBTU will be the gas with the lowest heating value. The lowest heating value found is 584 BTU/DSCF, implying emissions of 0.013 lbs PM/MMBTU. This conservative result is still a factor of 10 below the 0.10 lb/MMBTU most restrictive allowance identified in the introductory paragraph for any equipment at the facility.
The highest emission factor suggested in Table 3.3-1 and Table 3.4-1 of AP-42 for either gas-fired or diesel-fired reciprocating engines is 0.31 lbs/MMBTU. The largest engine in EUG 36, EUG 38, or in the Insignificant Activity group has a heat rating less than 5 MMBTUH. All engines are thus subject to the least restrictive standard of 0.6 lbs/MMBTU. The worst case PM emission factor for gas-fired reciprocating engines is 0.013 lbs/MMBTU and for diesel-fired reciprocating engines is 0.31 lbs/MMBTU which are both less than the standard of 0.6 lbs/MMBTU.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours and according to the other exceptions defined in this subchapter. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas there is very little possibility of exceeding these standards and compliance with the standard is presumed. Degreasing operations, painting operations which filter particulate emissions, non-heat set printing operations, other non-heat set evaporative VOC sources, petroleum product storage tanks, glycol dehydrators and sources which are vented inside a building which is usually occupied may be presumed to be in compliance with any opacity limit of 20% or greater.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards Heavy traffic areas, including the racks and the offices, are paved. Vehicular traffic in the unpaved areas is greatly restricted for safety reasons. Under normal operating conditions, this facility will not cause fugitive dust problems, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) (Applicable]
<u>Part 2</u> limits limits the ambient air impact of hydrogen sulfide (H_2S) emissions from any new or existing source to 0.2 ppm for a 24-hour average (equivalent to 280 μg/m^3). The facility has demonstrated compliance with this standard in November 2013.
<u>Paragraph 31-25(a)(1)</u> covers gas-fired fuel-burning equipment. The equipment listed below is presumed in compliance because this equipment burns only commercial pipeline quality natural gas or Subpart Ja compliance gas.

1. #7 Boiler
2. #8 Boiler
3. #9 Boiler
4. #2 Plat PH-5 heater
5. Coker B-1 heater
6. MEK H-101heater

The following pieces of fuel-burning equipment are not subject to OAC 252:100-31-25(a)(1) because the units were constructed prior to, and have not been modified since, the applicability date of July 1, 1972.

EU	Point ID	Const. Date
106A	#3 Boiler	1954
106B	#4 Boiler	1957
201N	CDU H-1,N,#7	1961
201S	CDU H-1,S,#8	1961
206	Unifiner H-2	1957
207	Unifiner H-3	1957
209	#2 Plat PH-1/2	1957
210	#2 Plat PH-3	1957
214	#2 Plat PH-7	1971
238	PDA B-30	1956
240	PDA B-40	1962
242	LEU H101	1963
244	LEU H-201	1963
246	MEK H-2	1959
202	CDU H-2	1961
203	CDU H-3	1961
243N	LEU H-102 North	1963
243S	LEU H-102 South	1963
213	#2 Plat PH-6	1957

It is not clear whether all of the fuel-burning equipment in EUG 36 and EUG 38 is new or existing, but the calculations supporting the emission estimates for these EUGs clearly demonstrate that the SO_2 emissions satisfy the standard of 0.2 lbs/MMBTU set by §25(a)(A).

Section 31-26 (Petroleum and natural gas processes)
As defined in §31-2, "petroleum and natural gas processes includes equipment used in processing crude and/or natural gas into refined products and includes catalytic cracking units, catalytic reforming units, and many others.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]

This subchapter limits new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.20 lbs of NO_X per MMBTU, three-hour average for gas-fired equipment, 0.30 lbs/MMBTU for liquid-fired equipment, and 0.70 lbs/MMBTU for solid fuel-fired equipment. Most of the fuel-burning equipment at this facility is either too small or was constructed, rebuilt, or modified before the effective date of February 14, 1972 for "new" equipment. The following table indicates the compliance status of affected units.

Equipment	MMBTUH	Emission factor and source
#7 Boiler	150	0.20 lb/MMBTU, stack test of identical boiler #9
#8 Boiler	150	0.20 lb/MMBTU, stack test of identical boiler #9
#9 Boiler	150	0.20 lb/MMBTU, stack test
#10 Boiler	214.6	0.06 lb/MMBTU, stack tests plus safety factor
#2 Plat PH-5	52	0.092 lb/MMBTU, stack test.
Coker B-1	60	0.09 lb/MMBTU, manufacturer's data, 0.06 lb/MMBTU per 7/22/92 stack test.
MEK H-101	81	0.15 lb/MMBTU, manufacturer's data.
ROSE Heater	76	0.03 lb/MMBTU, BACT limit
H2 Plant Heater	125	0.03 lb/MMBTU, BACT limit

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]

Affected processes under this subchapter include gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit. Standards are based on whether the source is new or existing, where any source constructed or modified after July 1, 1972 is considered to be "new." The facility operates an existing petroleum catalytic reforming unit. Standards are set for existing units located in nonattainment or former nonattainment areas. Since Tulsa County has never been non-attainment for CO, the facility is not affected by this subchapter.

OAC 252:100-37 (Volatile Organic Materials) [Applicable]

37-4(a) Exempts VOCs with vapor pressure less than 1.5 psia from Sections 15, 16, 35, 36, 37, and 38. EUGs 20, 23, 24, 25, and 28 qualify for this exemption.

37-15(a) Each VOC storage vessel with a capacity of more than 40,000 gallons shall be a pressure vessel capable of maintaining working pressures that prevent the loss of VOC or shall be equipped with one of three specified vapor control devices. Storage vessels subject to equipment standards in 40 CFR 60 (NSPS) Subparts K, Ka, or Kb are exempt from §§37-15(a) and (b) per §37-15(c). All storage vessels listed in EUGs 18, 19, 26, and 27 meet the requirements of 37-15(a). All other storage vessels that exceed 40,000 gallons contain VOCs less than 1.5 psia or are subject to NSPS Subparts K, Ka, or Kb.

37-15(b) Each VOC storage tank with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia must be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. All HRHT tanks that are affected sources have bottom fill lines (EUGs 18, 19, and 27). All other storage vessels that exceed 40,000 gallons contain VOCs less than 1.5 psia or are subject to NSPS Subparts K, Ka, or Kb.

The following list shows those vessels exempt under the 1.5 psia standard identified above.

EU	Point ID	BBL
20128	Tk6	1890
13559	Tk30	30,000
1356	Tk41	4200
13561	Tk50	1890
13562	Tk51	1890
13563	Tk155	54132
20129	Tk181	1000
6351	Tk190	55,000
13573	Tk277	7,000
6364	Tk279	7,000
6368	Tk312	7,000
6370	Tk315	7,000
6375	Tk401	55,000
13596	Tk582	4,061
NA	Tk696	1,700
6393	Tk747	10,000
5397	Tk751	10,000
13588	Tk27	55,000
NA	Tk84	963
NA	Tk85	963
6377	Tk405	72,443
13578	Tk406	71,526
6406	Tk1002	55,000
NA	Tk1005	4,800
15950	Tk1012	5,000
16561	Tk1039	120,000
13569	Tk224	55,000
13573	Tk277	7,000
NA	Tk881	2,090
NA	Tk992	1,815
NA	Tk993	1,815
6324	Tk152	7,000
13565	Tk158	63,709
NA	Tk472	3,080
NA	Tk983	15,000
NA	Tk984	15,000
NA	Tk986	6,000
NA	Tk987	6,000
20127	Tk1	1698
Tk11	Tk11	7000
6334	Tk15	7000
6335	Tk16	7000
Tk23	Tk23	7000

EU	Point ID	BBL
Tk26	Tk26	55000
20130	Tk28	38000
6339	Tk29	55000
Tk33	Tk33	55000
6343	Tk36	55000
Tk38	Tk38	1890
Tk45	Tk45	4200
Tk46	Tk46	4200
Tk52	Tk52	1890
Tk53	Tk53	1890
Tk54	Tk54	1890
Tk62	Tk62	4200
Tk65	Tk65	1890
Tk66	Tk66	1890
Tk68	Tk68	1890
Tk69	Tk69	1890
Tk71	Tk71	5680
Tk73	Tk73	5680
Tk74	Tk74	5680
Tk76	Tk76	1890
Tk79	Tk79	1890
Tk80	Tk80	1890
Tk81	Tk81	1890
Tk132	Tk132	1800
Tk133	Tk133	1800
Tk134	Tk134	7000
6344	Tk151	7000
15944	Tk159	55000
Tk192	Tk192	52300
15945	Tk193	52730
13567	Tk194	53100
Tk195	Tk195	55000
Tk196	Tk196	55000
6355	Tk215	50914
15946	Tk217	7000
13568	Tk218	7000
Tk223	Tk223	7000
Tk227	Tk227	7000
Tk228	Tk228	1890
Tk229	Tk229	1890
Tk232	Tk232	1890
Tk233	Tk233	1890
Tk234	Tk234	1890

EU	Point ID	BBL
Tk235	Tk235	1890
Tk236	Tk236	1890
Tk237	Tk237	1890
Tk240	Tk240	1500
Tk252	Tk252	7000
Tk271	Tk271	1890
6363	Tk272	1890
Tk273	Tk273	7000
Tk274	Tk274	7000
Tk275	Tk275	7000
Tk276	Tk276	7000
Tk305	Tk305	7000
Tk317	Tk317	7000
Tk318	Tk318	7000
Tk319	Tk319	1890
Tk320	Tk320	1890
Tk321	Tk321	1890
Tk322	Tk322	1890
6371	Tk323	7000
Tk327	Tk327	1890
Tk328	Tk328	1890
Tk329	Tk329	1890
Tk331	Tk331	7000
Tk332	Tk332	7000
Tk390	Tk390	7000
Tk391	Tk390	5000
Tk392	Tk392	5000
Tk393	Tk393	1000
Tk394	Tk394	1120
Tk396	Tk396	5940
Tk397	Tk397	5940
6373	Tk398	2600
6374	Tk399	2600
6377	Tk404	72273
6379	Tk407	71526
6380	Tk412	51773
6386	Tk445	74098
Tk471	Tk471	3780
Tk645	Tk645	1500
Tk646	Tk646	1500
Tk649	Tk649	1008
Tk650	Tk650	10000
Tk675	Tk675	1500

EU	Point ID	BBL
Tk691	Tk691	2400
Tk692	Tk692	2400
Tk693	Tk693	2400
Tk694	Tk694	2400
Tk700	Tk700	15000
13585	Tk701	15000
13584	Tk702	7000
Tk800	Tk800	7000
15958	Tk801	15000
13586	Tk802	15000
15949	Tk803	15000
Tk807	Tk807	4200
Tk828	Tk828	30000
Tk829	Tk829	30000
Tk830	Tk830	30000
Tk831	Tk831	30000
Tk835	Tk835	2000
6404	Tk838	2000
Tk847	Tk847	2032
Tk848	Tk848	2032
Tk851	Tk851	2088
Tk852	Tk852	4025
Tk853	Tk853	4025
Tk854	Tk854	4025
Tk855	Tk855	4025
Tk856	Tk856	4025
Tk857	Tk857	2011
Tk861	Tk861	1000
Tk865	Tk865	1890
Tk867	Tk867	1675
13587	Tk870	5300
Tk875	Tk875	2090
Tk876	Tk876	3000
Tk877	Tk877	2090
Tk878	Tk878	2090
Tk879	Tk879	2090
Tk880	Tk880	3000
Tk882	Tk882	20000
Tk883	Tk883	1000
Tk884	Tk884	1000
Tk885	Tk885	1000
Tk886	Tk886	10492
Tk887	Tk887	19500

EU	Point ID	BBL
Tk888	Tk888	10492
Tk891	Tk891	1000
Tk893	Tk893	10500
Tk898	Tk898	2455
Tk913	Tk913	2090
Tk914	Tk914	2090
Tk916	Tk916	2090
Tk918	Tk918	30000
Tk921	Tk921	2094
Tk922	Tk922	3058
Tk923	Tk923	2084
Tk924	Tk924	4455
Tk925	Tk925	4455
Tk926	Tk926	1313
Tk927	Tk927	1313
Tk928	Tk928	4455
Tk929	Tk929	4455
Tk930	Tk930	1313
Tk931	Tk931	1313
Tk932	Tk932	3058
Tk933	Tk933	1000
Tk934	Tk934	1000
Tk935	Tk935	1000
Tk936	Tk936	1000
Tk937	Tk937	1000
Tk938	Tk938	1000
Tk943	Tk943	1000
Tk944	Tk944	1000
Tk955	Tk955	1000
TkAGT1	TkAGT1	2000
TkAGT2	TkAGT2	1000
TkAGT3	TkAGT3	1000
TkAGT4	TkAGT4	2000
Tk939	Tk939	1000
Tk940	Tk940	1000
Tk941	Tk941	1000
Tk942	Tk942	1000

The following list shows those vessels exempt under the NSPS standard identified above.

EU	Point ID	Nominal Capacity (BBLs)
6338	Tk25	55,000
13594	Tk1061	80,000
20126	Tk1070	5,377
NA	Tk1080	3,200
6402	Tk782	15,000
13591	Tk583	4,800
6350	Tk189	55,000
--	Tk1038	95,000

37-16(a) (Loading facilities with throughput greater than 40,000 gallons/day.) 37-16(b) (Loading facilities with throughput equal to or less than 40,000 gallons/day.) The following loading racks are not subject to OAC 252:100-37-16 because the units do not load VOC containing material, per §37-4(a).

EU	Equipment Point ID	Installed Date
NA	Black Oil Loading Rack	1937
NA	Extract Truck Loading Rack	1993
NA	Extract Rail Loading Rack	1930
NA	Wax Truck Loading Rack	1979
NA	Wax Rail Loading Rack	1917
NA	LOB Rail Loading Rack	1967
NA	LOB Truck Loading Rack	1978
NA	Resid Truck Loading Rack	1962
NA	Diesel Rail Loading Rack	1986
NA	Coke Truck Loading Area	1991

Section 37-36 requires fuel-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion. Refinery fuel combustion devices are designed to provide essentially complete combustion of organic materials.

Section 37-37 regulates water separators that receive water containing more than 200 gallons per day of VOC. All oil/water separators listed in EUG 35 receiving VOC material with vapor pressure greater than 1.5 psia are sealed per 37-37(1). Separators built since 7/1/72 are either sealed irrespective of the 200-gpd trigger or do not process 200 gpd organics per records on file.

OAC 252:100-39 (VOC in Non-Attainment and Former Nonattainment Areas) [Applicable]
Section 39-15 (Petroleum Refinery Equipment Leaks) EPA test Method 21 is specified for detecting equipment leaks. VOC with vapor pressure less than 0.0435 is exempt. Components covered by this section include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open-ended pipes. All such components are tested in a monitoring program per 15(f); actions and repairs are conducted per 15(c); records are kept per 15(g); quarterly reports are made per 15(h); and monitoring logs are retained on-site for least two years.
Section 39-16 (Petroleum refinery process unit turnaround) Vented organic material must either be controlled per 39-16(b)(1) & (2) or exempted per 39-16(b)(4). Requirements for contents of the 15-day notification are listed in 39-16(b)(3). HFTR has provided the appropriate notices for past turnarounds and is in compliance based on standard unit turnaround practices that meet requirements.
Section 39-17 (Petroleum refinery vacuum producing system) The vacuum system at the CDU vacuum towers, T-2 and T-3, employs steam ejectors, surface condensers, and a mechanical vacuum pump to deliver vacuum gases to the CDU H-2 heater. If the vacuum pump fails, the third stage jet system is used to deliver gases to H-2.
The vacuum system at the LEU T-201 vacuum tower employs ejectors and surface condensers. The surface condenser gases are in turn ejected with natural gas into dedicated burners in the LEU H-102 heater. Both vacuum gas streams are disposed by direct combustion into the firebox of a large heater. Flowing this material to the unit heater obviates a requirement that the pilot flame be monitored. Maintenance records on the systems are being kept.
Section 39-18 (Petroleum refinery effluent water separators) Separators listed in EUG 35 receiving VOC material are sealed and are in compliance by separator design.
Section 39-30 (Petroleum liquid storage in vessels with external floating roofs) Storage tank 874 listed in EUG 27 is subject to 39-30(c). Storage vessels listed in EUG 19 are exempt per 39-30(b)(4) because they are subject to 40 CFR Part 63 Subpart CC. Storage vessels listed in EUG 22 are exempt per 39-30(b)(3) because they are subject to 40 CFR Part 60 Subpart Kb. Storage vessels listed in EUG 20, 23, 24, 25, and 28 are exempt per 39-30(b)(2)(C) because they contain liquids with true vapor pressure less than 1.5 psia.
Section 39-40 (Cutback asphalt (paving))
Cutback liquefied asphalt cannot be applied or prepared in the facility without prior written consent of the Division Director.
Section 39-41 (Storage, loading and transport/delivery of VOCs)
HFTR stores and loads gasoline delivery trucks, but does not deliver gasoline. HFTR is subject to the storage and loading part of this section of the subchapter. The gasoline loading operation has been moved to the HEP permit.
Subsection 39-41(a) Storage of VOCs in vessels with storage capacities greater than 40,000 gallons. Each vessel with a capacity greater than 40,000 gallons storing VOC with a true vapor pressure that exceeds 1.50 psia must have either a floating internal or external roof that meets the requirement of this section. Tank inspections are documented electronically on the Refinery Tanks Database. Electronic documentation records the date of the inspection, any defects noted, and the initials of the inspector. Storage tanks in EUG 18, 19, 21, 22, and 27 are subject. Storage tanks in EUG 20, 23, 24, and 25 are exempt because the VOC vapor pressure is less than 1.5 psia.

Subsection 39-41(b) Storage of VOCs in vessels with storage capacities of 400-40,000 gallons. Each vessel with this capacity and storing a VOC with a vapor pressure greater than 1.5 psia is equipped with a bottom fill line.
Subsection 39-41(c) Loading of VOCs. The truck terminal previously of EUG 13 has been closed.
Subsection 39-41(d) Transport/delivery. No delivery vessel incapable of accepting displaced vapors and designated as vapor tight is allowed to load at the facility's loading terminal.
Subsection 39-41(e) Additional requirements for Tulsa County. Only Paragraphs 3 and 4 apply.
§39-41(e)(3) (Loading of VOCs) requires that the stationary loading facility be checked annually using EPA Method 21. Leaks greater than 5,000 ppmv shall be repaired within 15 days. The facility appears to be in compliance, based on current leak test records.
§39-41(e)(4) (Transport/delivery vessel requirement) requires that transport vessels be maintained vapor tight and must be capable of receiving and storing vapors for ultimate delivery to a vapor recovery/disposal system. Any defect that impairs vapor tightness must be repaired within five days. Certification of vapor tightness and of repairs must be provided and no vessel shall be loaded without demonstrating the proper certification. DEQ may perform spot checks of vapor tightness and may require owner/operators to make necessary repairs. This facility and the transports loading there have been in compliance.

Section 39-42 (Metal cleaning) contains requirements for cold cleaning, vapor degreasing, and conveyorized degreasing. The facility has no vapor or conveyorized units, so only §39-42(a) applies. All equipment shall have a cover or door that can be easily operated with one hand, shall provide an internal drain board that will allow lid closure if practical or provide an external drainage facility, shall have an attached permanent, conspicuous label summarizing the operating requirements of OAC 252:100-39-42(a)(2). Control requirements are identified in §39-42(a)(3) for those solvents with vapor pressure greater than 0.6 psi.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superseded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this

subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not in source category
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-35	Control of CO	not in source category
OAC 252:100-39-43	Graphic Arts	not in source category
OAC 252:100-39-44	Tire Mfg.	not in source category
OAC 252:100-39-45	Dry Cleaning	not in source category
OAC 252:100-39-46	Parts Coating	not in source category
OAC 252:100-39-47	Aerospace Coating	not in source category
OAC 252:100-39-49	Fiberglass Mfg.	not in source category
OAC 252:100-47	MSW Landfills	not in source category

SECTION XI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Emissions of several regulated pollutants exceed the major source level of 100 TPY for a listed source. PSD will apply to any future project whose added emissions exceed the significance levels: CO 100 TPY, NO_X 40 TPY, SO_2 40 TPY, $PM_{2.5}$ 10 TPY, PM_{10} 15 TPY, VOC 40 TPY, or GHG 75,000 TPY.

NSPS, 40 CFR Part 60 [Subparts A, Db, J, Ja, K, Ka, Kb, GGG, JJJJ, and GGGa Applicable]
The following paragraphs are general in nature, with some reference to specific facilities. The Specific Conditions contain specific requirements under NSPS for all affected facilities.

Subpart A specifies general control device requirements for control devices used to comply with applicable subparts. EUG 11 must comply with § 60.18 and the corresponding regulatory section § 60.485(g) by physical design and per the alternate test methods approved by DEQ and discussed below. Records kept on-site to meet monitoring and recordkeeping requirements of § 60.486(d)(1), (2), and (3) are also discussed below. The facility is in compliance with § 60.7 (b) as to Startup/Shutdown/Malfunction records, per current records.

Subpart D, (Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971)
This is not applicable because there are no fossil-fuel-fired steam generators with a heat input greater than 250 MMBTUH.

Subpart Da (Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978)
This is not an applicable requirement because there are no electric utility steam generating units.

Subpart Db (Industrial-Commercial-Institutional Steam Generating Units for Which Construction Is Commenced After June 19, 1984). The following units was constructed or modified after the effective date of the standard.

EU	Point ID	Construction Date
--	#10 Boiler	2013

The following units were constructed or modified prior to the effective date of the standard.

EU	Point ID	Construction Date
109	#7 Boiler	1975
110	#8 Boiler	1976
111	#9 Boiler	1976

The new Boiler #10 is subject to NSPS Subpart Db. Since Boiler #10 does not burn coal or No. 2 fuel oil, it is only subject to Sections § 60.44b, 60.46b, 60.48b, and 60.49b of this subpart (standards of Subpart Db for SO_2 and PM do not apply to gas-fueled boilers). Requirements include:

1. Compliance testing for particulate matter and nitrogen oxides (§ 60.46b). The emission standard for oxides of nitrogen is 0.2 lb/MMBTU per § 60.44b(a), including periods of start-up, shutdown and malfunction (§ 60.44b(h). Compliance with the NO_X standard is to be demonstrated on a rolling 30-day basis, except that the initial performance test shall demonstrate compliance on a 24-hour basis and any subsequent performance tests shall demonstrate compliance on a 3-hour basis (§ 60.44b(i, j)).
2. Emissions monitoring for nitrogen oxides (§ 60.48b). The applicant installed a continuous emission monitor (CEM) to monitor NOx on boiler #10.
3. Reporting and recordkeeping (§ 60.49b). HFTR will record natural gas and refinery gas usage and CEMs data.

Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units for Which Construction Is Commenced After June 9, 1989)
There are no applicable units constructed or modified after the effective date of the standard.

Subpart J (Petroleum Refineries)
The following units are not subject to NSPS Subpart J because they were constructed prior to the applicability date of June 11, 1973.

EU	Point ID	Construction Date
201N	CDU H-1,N,#7	1961
201S	CDU H-1,S,#8	1961
202	CDU H-2	1961 (1)
203	CDU H-3	1961 (1)
206	Unifiner H-2	1957
207	Unifiner H-3	1957
209	#2 Plat PH-1/2	1957
210	#2 Plat PH-3	1957
213	#2 Plat PH-6	1957
214	#2 Plat PH-7	1971
238	PDA B-30	1956
240	PDA B-40	1962
242	LEU H101	1963
243N	LEU H102	1963[1]
243S	LEU H102	1963[1]
244	LEU H-201	1963
246	MEK H-2	1959

(1) Low NO_X burners were installed in units CDU H-2 and H-3 and LEU H-102 in 1989. As stated in the construction permit (T89-37; August 11, 1989), this installation did not qualify as a modification or reconstruction, and thus, the units remain exempted from this rule.

The following units were constructed or modified after the applicability date and will only burn natural gas or refinery fuel gas complying with NSPS Subpart J Standards.

EU	Point ID	Construction Date
109	#7 Boiler	1975
110	#8 Boiler	1976
111	#9 Boiler	1976
212	#2 Plat PH-5	1990
225	Coker B-1	1992 (Permit T91-110)
245	MEK H-101	1977 (Permit 77-006-0)

The WPU and Coker flare, EU-269 and EU268 (EUG-11) were subject to NSPS Subpart J due to the Refinery Wide Global Consent Decree Settlement. The LEU/MEK flares were already subject. These flares were modified after May 14, 2007, and are therefore subject to the more stringent requirements of Subpart Ja. They are protected by water seal from combusting routinely generated refinery gases.

Subpart Ja, Petroleum Refineries. On June 24, 2008, EPA promulgated standards for new, modified, or reconstructed affected facilities at petroleum refineries. The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, flares, fuel gas combustion devices, including process heaters, and sulfur recovery plants. Only those affected facilities that begin construction, modification, or reconstruction after May 14, 2007, are subject to this subpart. Fuel gas combustion device means any equipment, such as process heaters, boilers used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. All of the flares (LEU, Coker, Platformer) have been reconstructed or modified after May 14, 2007. Because the LEU flare was already subject to NSPS J it was required to comply upon startup after modification, or September 7, 2011. The Coker and Platformer flares must comply by November 11, 2015. Boiler 10 is new equipment subject to Subpart Ja. The change to RFG makes Heaters PH-4 and Plat H-3 subject to Subpart Ja for SO_2 only since no increase in NO_x is expected. The two new heaters (Hydrogen Plant and ROSE Unit) will be subject to emissions and monitoring standards of Subpart Ja.

Subpart K (Petroleum Liquids) applies to volatile organic liquids storage vessels for which construction, reconstruction, or modification commenced after June 11, 1973, or before May 19, 1978, which have a capacity of 40,000 gallons or more, and which do not contain organic materials specifically exempted. Those materials specifically exempted include diesel, jet fuel, kerosene, and residual fuel oils. Per 60.112, controls are required if storing material above a true vapor pressure (TVP) of 1.5 psia. Records of stored material stated in § 60.113(a) are not required if the stored material is below a Reid vapor pressure (RVP) of 1.0 psia, but are required regardless of RVP if TVP is greater than 1.0 psia, per § 60.113(d)(1). Tanks listed in EUG 25 are exempt from recordkeeping because material stored is below 1.0 psia RVP and TVP.

Subpart Ka (Petroleum Liquids) applies to volatile organic liquids storage vessels for which construction, reconstruction, or modification commenced after May 18, 1978, but before July 23, 1984, which have a capacity of 40,000 gallons or more, and which do not contain organic materials specifically exempted. Those materials specifically exempted include diesel, kerosene, and residual fuel oils. Per 60.112(a) controls are not required if stored material is below 1.5 RVP. Records of stored material per 60.115(a) are required if RVP is above 1.0, but not if below 1.0 per 60.115(d)(1). Tanks in EUG 24 are exempt from recordkeeping.

Subpart Kb (VOL Storage Vessels) applies to volatile organic liquids storage vessels for which construction, reconstruction, or modification commenced after July 23, 1984, and which have a capacity of 75 cubic meters (m^3) or more. Tanks with capacities greater than or equal to 151 m^3 and storing VOL with TVP less than 3.5 kPa ($\approx$ 0.5 psia) are exempt from Kb, as are tanks with capacities greater than or equal to 75 m^3 and less than 151 m^3 that store VOL with TVP less than 15.0 kPa ($\approx$ 2.2 psia). Tanks with capacities greater than or equal to 151 m^3 and storing VOL with TVP equal to or greater than 5.2 kPa ($\approx$ 0.75 psia) but less than 76.6 kPa ($\approx$ 11.1 psia) are required to have the controls described in §60.112b(a). Tanks with capacities greater than or equal to 75 m^3 and less than 151 m^3 and storing VOL with TVP equal to or greater than 27.6 kPa ($\approx$ 4.0 psia) but less than 76.6 kPa are also required to have the controls described in § 60.112b(a). Tanks with TVP greater than 76.6 kPa must install the closed systems described in § 60.112b(b). Tanks subject to the controls of § 60.112b are subject to the testing and inspection requirements of § 60.113b and the reporting and recordkeeping requirements of § 60.115b. All tanks, regardless of controls, are subject to the monitoring requirements of §60.116b. Compliance is per monitoring specified at § 60.113(b), and records and reporting as specified at sections § 60.115(b) and 60.116(b). Tanks in EUGs 21, 22, and 23 are affected facilities under Subpart Kb. Tank inspections are documented electronically on the Refinery Tanks Database. Electronic documentation records the date of the inspection, any defects noted, and the initials of the inspector.

The permit allows for construction of new tanks provided that emissions do not exceed the stated cap. Specifications for the new tanks are not yet finalized. The new tanks are presumed to be subject to Subpart Kb.

The following petroleum/volatile organic liquid storage tanks are not subject to NSPS Subparts K, Ka, or Kb because the tanks were constructed or modified prior to the applicability dates.

EU	Tank #	Nominal BBL	Year
6336	21	33,178	1916
6337	22	33,284	1916
6340	31	35,411	1940
6346	153	47,858	1917
6359	242	48,654	1917
6360	244	55,000	1917
6387	473	1,500	1979
6382	423	51,163	1923
1591	432	74,529	1953
6383	433	50,910	1923
6385	435	74,132	1953
1359	502	7,000	1965
6392	742	10,000	1948
6393	747	10,000	1948
5397	751	10,000	1949
6367	307	10,000	1946
6398	752	10,000	1949
6396	750	10,000	1972
6399	755	10,000	1950
6401	779	10,000	1953
6369	314	7,000	1922
20128	6	1890	1916
6333	13	55,000	1916
13559	30	30,000	1917
1356	41	4200	1929
13561	50	1890	1917
13562	51	1890	1917
13563	155	54132	1917
20129	181	1000	1928
6347	185	55,000	1922

EU	Tank #	Nominal BBL	Year
6348	186	55,000	1922
6349	187	55,000	1922
13592	188	55,000	1922
6351	190	55,000	1922
13570	258	1,890	1917
13571	259	1,890	1917
13573	277	7,000	1917
6364	279	7,000	1947
13575	282	7,000	1917
6368	312	7,000	1922
6370	315	7,000	1917
6375	401	55,000	1922
13594	546	1,700	1943
13596	582	4,061	1936
NA	696	1700	1948
6405	874	121,275	1965
6333	13	55,000	1917
8347	185	55,000	1922
6348	186	55,000	1922
6349	187	55,000	1922
13592	188	55,000	1922
6405	874	121,275	1965
20127	1	1,698	1916
Tk11	11	7,000	1916
6334	15	7,000	1916
6335	16	7,000	1916
Tk23	23	7,000	1916
Tk26	26	55,000	1916
20130	28	38,000	1964
6339	29	55,000	1964
Tk33	33	55,000	1917
6343	36	55,000	1917
Tk38	38	1,890	1928
Tk45	45	4,200	1917
Tk46	46	4,200	1917
Tk52	52	1,890	1917
Tk53	53	1,890	1917
Tk54	54	1,890	1917
Tk62	62	4,200	1917
Tk65	65	1,890	1917
Tk66	66	1,890	1917
Tk68	68	1,890	1917
Tk69	69	1,890	1917

EU	Tank #	Nominal BBL	Year
Tk71	71	5,680	1917
Tk73	73	5,680	1917
Tk74	74	5,680	1917
Tk76	76	1,890	1917
Tk79	79	1,890	1917
Tk81	81	1,890	1917
Tk132	132	1,800	1922
Tk133	133	1,800	1922
Tk134	134	7,000	1922
6344	151	7,000	1917
15944	159	55,000	1925
6352	191	55,000	1922
Tk192	192	52,300	1943
15945	193	52,730	1917
13567	194	53,100	1966
Tk195	195	55,000	1917
Tk196	196	55,000	1916
6355	215	50,914	1917
15946	217	7,000	1917
13568	218	7,000	1968
Tk223	223	7,000	1917
Tk227	227	7,000	1917
Tk228	228	1,890	1917
Tk229	229	1,890	1917
Tk232	232	1,890	1917
Tk233	233	1,890	1917
Tk234	234	1,890	1917
Tk235	235	1,890	1917
Tk236	236	1,890	1917
Tk237	237	1,890	1917
Tk240	240	1,500	1917
Tk252	252	7,000	1966
Tk271	271	1,890	1917
6363	272	1,890	1917
Tk273	273	7,000	1917
Tk274	274	7,000	1929
Tk275	275	7,000	1963
Tk276	276	7,000	1917
Tk305	305	7,000	1929
Tk317	317	7,000	1917
Tk318	318	7,000	1917
Tk319	319	1,890	1917
Tk320	320	1,890	1917

EU	Tank #	Nominal BBL	Year
Tk321	321	1,890	1917
Tk322	322	1,890	1917
6371	323	7,000	1917
Tk327	327	1,890	1917
Tk328	328	1,890	1917
Tk329	329	1,890	1917
Tk331	331	7,000	1917
Tk332	332	7,000	1917
Tk390	390	7,000	1929
Tk391	390	5,000	1929
Tk392	392	5,000	1929
Tk393	393	1,000	1930
Tk394	394	1,120	1930
Tk396	396	5,940	1963
Tk397	397	5,940	1963
6373	398	2,600	1928
6374	399	2,600	1928
Tk471	471	3,780	1917
Tk645	645	1,500	1938
Tk646	646	1,500	1936
Tk649	649	1,008	1937
Tk650	650	10,000	1940
Tk675	675	1,500	1942
Tk691	691	2,400	1942
Tk692	692	2,400	1942
Tk693	693	2,400	1942
Tk694	694	2,400	1942
Tk700	700	15,000	1942
13585	701	15,000	1942
13584	702	7,000	1942
6400	775	55,000	1916
Tk800	800	7,000	1956
15958	801	15,000	1956
13586	802	15,000	1956
15949	803	15,000	1956
Tk807	807	4,200	1958
Tk828	828	30,000	1960
Tk829	829	30,000	1960
Tk830	830	30,000	1960
Tk831	831	30,000	1960
Tk835	835	2,000	1960
6404	838	2,000	1960
Tk847	847	2,032	1961

EU	Tank #	Nominal BBL	Year
Tk848	848	2,032	1961
Tk851	851	2,088	1961
Tk852	852	4,025	1962
Tk853	853	4,025	1962
Tk854	854	4,025	1962
Tk855	855	4,025	1962
Tk856	856	4,025	1962
Tk857	857	2,011	1962
Tk861	861	1,000	1968
Tk865	865	1,890	1963
Tk867	867	1,675	1964
13587	870	5,300	1963
Tk875	875	2,090	1966
Tk876	876	3,000	1966
Tk877	877	2,090	1966
Tk878	878	2,090	1966
Tk879	879	2,090	1966
Tk880	880	3,000	1966
Tk882	882	20,000	1967
Tk883	883	1,000	1967
Tk884	884	1,000	1967
Tk885	885	1,000	1967
Tk886	886	10,492	1967
Tk887	887	19,500	1967
Tk888	888	10,492	1967
Tk891	891	1,000	1968
Tk893	893	10,500	1972
Tk898	898	2,455	1917
Tk913	913	2,090	1917
Tk914	914	2,090	1917
Tk916	916	2,090	1917
Tk918	918	30,000	1972
Tk921	921	2,094	1966
Tk922	922	3,058	1966
Tk923	923	2,084	1966
Tk924	924	4,455	1966
Tk925	925	4,455	1966
Tk926	926	1,313	1966
Tk927	927	1,313	1966
Tk928	928	4,455	1966
Tk929	929	4,455	1966
Tk930	930	1,313	1966
Tk931	931	1,313	1966

EU	Tank #	Nominal BBL	Year
Tk932	932	3,058	1966
Tk933	933	1,000	1966
Tk934	934	1,000	1966
Tk935	935	1,000	1966
Tk936	936	1,000	1966
Tk937	937	1,000	1966
Tk938	938	1,000	1966
Tk939	939	1,000	1966
Tk940	940	1,000	1966
Tk941	941	1,000	1966
Tk942	942	1,000	1966
Tk943	943	1,000	1966
Tk944	944	1,000	1966
Tk955	955	1,000	1966
TkAGT1	AGT1	2,000	1922
TkAGT2	AGT2	1,000	1922
TkAGT3	AGT3	1,000	1922
TkAGT4	AGT4	2,000	1922

Subpart GG (Stationary Gas Turbines)
There are no stationary gas turbines on-site.

Subpart UU (Asphalt Processing and Asphalt Roofing) Per 40 CFR 60.470, affected facilities include asphalt storage tanks and blowing stills at refineries, for which construction or modification commenced after May 26, 1981. There are no active asphalt operations on-site.

Subpart VV (Equipment Leaks of VOC in SOCMI) Although the refinery is not an affected facility, the refinery MACT (40 CFR 63 Subpart CC) makes extensive reference to this NSPS subpart.

Subpart VVa, (Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOMCI)) This subpart affects equipment constructed, reconstructed or modified after November 7, 2006. NSPS, Subpart GGGa requires equipment constructed, reconstructed or modified after November 7, 2006 in VOC service to comply with paragraphs §§ 60.482-1a through 60.482-10a, 60.484a, 60.485a, 60.486a, and 60.487a except as provided in § 60.593a. Most of the equipment at the refinery was constructed prior to November 7, 2007 and is covered under NSPS, Subpart GGG or NESHAP Subpart CC. The new equipment in the Coker, the blowdown system, is a relief system modification that is subject to NSPS, Subpart GGGa. Additionally, a Flare Gas Recovery Unit has been installed as a new process unit and is also subject to this subpart. The new and modified process units will be subject to Subpart GGGa.

Subpart XX (Bulk Gasoline Terminals) Per 40 CFR 60.500, affected facilities include all loading racks at a bulk gasoline terminal, for which construction or modification commenced after December 17, 1980. Further, any replacement of components commenced before August 18, 1983, in order to comply with emission standards adopted by the Oklahoma State Department of Health or the Tulsa City/County Health Department are not to be considered a reconstruction under 40 CFR 60.15. The gasoline loading racks have been shut down or moved to the HEP permit.

Subpart GGG (Equipment Leaks of VOC in Petroleum Refineries) This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service which commenced construction or modification after January 4, 1984, and which is located within a process unit in a petroleum refinery. Subpart GGG requires the leak detection, repair, and documentation procedures of NSPS Subpart VV. Compressors in hydrogen service (defined as serving streams more than 50% by volume hydrogen) are exempt from all requirements other than demonstrating that a stream can never be reasonably expected to contain less than 50% by volume hydrogen. Those pressure-relief devices vented to a control device (flare) are exempted from periodic monitoring requirements. Equipment in EUG 7 is subject to this subpart and compliance records are maintained on-site in an electronic database. Equipment in EUG 8 is subject to NESHAP MACT Subpart CC, and equipment in EUG 9 is subject to OAC 252:100-39-15.

All Leak Detection and Repair (LDAR) reporting required by 40 CFR 60, Subpart GGG (semi-annual), and 40 CFR 63, Subpart CC (semi-annual) has been consolidated to simplify overlapping requirements, based on discretion granted to the state authorities by EPA. All LDAR reporting is included in the MACT Semi-annual report covering all monitoring required from January 1st through June 30th and July 1st through December 31st. Reports are due 60 days after the end of each six month period per 40 CFR 63.654(g).

Subpart GGGa (Equipment Leaks of VOC in Petroleum Refineries) This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after November 7, 2006, and which is located at a petroleum refinery. This subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Subpart GGGa requires the leak detection, repair, and documentation procedures of NSPS, Subpart VVa. All affected equipment which commenced construction or modification after November 7, 2006, in VOC service and not in HAP service is subject to this subpart. In accordance with NESHAP Subpart CC, § 63.640(p)(2), equipment leaks that are also subject to the provisions of 40 CFR part 60, Subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, Subpart GGGa. The group of all the equipment (defined in §60.591a) within a process unit is an affected facility. The components in the West Flare Gas Recovery Unit are subject to Subpart GGGa. The new fugitive leakage components in the proposed new hydrogen plant and the fugitive leakage components in the modified ROSE (formerly PDA) unit will be subject to Subpart GGGa. The MEK Unit will also be modified and made subject to Subpart GGGa.

Subpart QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems) applies to individual drain systems, oil-water separators, and aggregate facilities located in petroleum refineries and for which construction, reconstruction, or modification commenced after May 4, 1987. All wastewater systems at the West Refinery were constructed or modified prior to the effective date of the standard.

Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI-ICE), promulgates emission standards for all new SI engines ordered after June 12, 2006, and all SI engines modified or reconstructed after June 12, 2006, regardless of size. The specific emission standards (either in g/hp-hr or as a concentration limit) vary based on engine class, engine power rating, lean-burn or rich-burn, fuel type, duty (emergency or non-emergency), and numerous manufacture dates. Engine manufacturers are required to certify certain engines to meet the emission standards and may voluntarily certify other engines. An initial notification is required only for owners and operators of engines greater than 500 HP that are non-certified. Emergency engines will be required to be equipped with a non-resettable hour meter and are limited to 100 hours per year of operation excluding use in an emergency (the length of operation and the reason the engine was in operation must be recorded). The emergency generator in EUG-41 is subject to the applicable emission standards and all applicable testing, monitoring, recordkeeping, and reporting requirements.

NESHAP, 40 CFR Part 61 [Subparts M and FF Applicable]

Subpart J (Equipment Leaks {Fugitive Emission Sources} of Benzene)
Affected sources are equipment items in "benzene service," which is defined to mean that they contact a stream with at least 10% benzene content by weight. The facility has no items in benzene service.

Subpart M (Asbestos) Molded or wet-applied friable asbestos insulation installation or reinstallation is prohibited per 61.148. The most likely activity that might be affected is the renovation or demolition of structures or equipment containing asbestos. Rules concerning such activities are found in §§60.145 and 60.150.

Subpart V (Equipment Leaks {Fugitive Emission Sources}) Affected sources are equipment items in "VHAP service," which is defined to mean that they contact a stream with at least 10% of a volatile HAP content by weight. The facility has no items in VHAP service.

Subpart Y (Benzene Emissions from Benzene Storage Vessels) Affected sources are vessels storing benzene. The facility currently has no benzene storage vessels.

Subpart BB (Benzene Emissions from Benzene Transfer Operations) Affected sources are all loading racks at which benzene is loaded into tank trucks, railcars, or marine vessels at each benzene production facility and each bulk terminal. Specifically exempted from this regulation are loading racks at which only the following are loaded: benzene-laden waste (covered under Subpart FF of this part), gasoline, crude oil, natural gas liquids, or petroleum distillates. The facility has none of the affected sources.

Subpart FF (Benzene Waste Operations) Affected sources are benzene-containing waste streams, as identified in EUG 12. Numerous standards apply to tanks, impoundments, and other activities if the total annual benzene (TAB) quantity exceeds 10 megagrams. Test methods and procedures used in calculating the TAB are found in § 61.355, paragraphs (a) through (c). Because the refinery has TAB less than 10 Mg, it is subject to only the recordkeeping, reporting, and testing requirements found in §§61.355, 356, and 357.

NESHAP, 40 CFR Part 63 [Subparts CC, UUU, ZZZZ, DDDDD and GGGGG Applicable]
The following paragraphs are general in nature, with some reference to specific facilities. The Specific Conditions contain specific requirements under NESHAP for all HFTR affected facilities.

Subpart F (Synthetic Organic Chemical Manufacturing Industry) The refinery is not a SOCMI facility.

Subpart G (Synthetic Organic Chemical Manufacturing Industry Process Vents, Storage Vessels, Transfer Operations, and Wastewater) Although the refinery is not a SOCMI facility, the refinery MACT (NESHAP Subpart CC) references provisions of this subpart.

Subpart H (Hazardous Organic NESHAPS {HON} Equipment Leaks) This MACT contains standards that must be referenced through other MACTs. The refinery is not an affected facility under this subpart.

Subpart R (Gasoline Distribution Facilities {Bulk Gasoline Terminals and Pipeline Breakout Stations}) The refinery is not an affected facility under this subpart, although some provisions of this subpart and of NSPS Subpart XX are invoked by NESHAP Subpart CC.

Subpart Q (Industrial Process Cooling Towers) The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources. The refinery ceased the use of chromium-based treatment before this MACT was issued.

Subpart Y (Marine Tank Vessel Tank Loading Operations) The refinery has no marine vessel loading capability.

Subpart CC (Petroleum Refineries) Affected facilities include process vents, storage vessels, wastewater streams and treatment, equipment leaks, gasoline loading racks, marine vessel loading systems, and pipeline breakout stations. Of the facilities named in Subpart CC, storage tanks, equipment leaks, process vents, wastewater streams and treatment, and a gasoline loading rack are affected facilities at HFTR.

Storage tanks
Existing storage tanks with HAP concentrations above 4%$_W$ and which have vapor pressures above 1.5 psia are required to implement controls. All tanks in EUGs 18 and 19 are Group 1 Storage Vessels as defined in § 63.641 and are to be controlled and monitored per § 63.646. Reports and records required for these tanks are found at § 63.654. General Provisions for startup/shutdown/malfunction (SSM) plans, as defined at § 63.641, are found at 40 CFR § 63.6(e)(3). Semi-annual and immediate reporting requirements are listed at § 63.10(d)(5). Electronic documentation, including the date of the inspection, any defects noted, and the initials of the inspector, is maintained on-site in the facility's "Refinery Tanks Database."

EUG 20 lists Group 2 Storage Vessels as defined at § 63.641. Subparagraph § 63.654(i)(1)(iv) requires a determination of Group 2 Tanks. The facility maintains a list of tanks that do not contain any HAPs and are not Group 2 Tanks per § 63.640(a)(2).

Process Vents
Any refinery unit process miscellaneous vent with greater than 20 ppmv HAPs and which emits more than 33 kg/day of VOC is subject to control requirements. Subpart CC requires affected vents to be equipped with 98% efficient controls, be vented to a flare, be vented to a combustion unit firebox, or be reduced to 20 ppmv HAP or less. Group 1 Process vents are listed in EUG 14 and Group 2 Process vents are listed in EUG 15. Group 1 Process Vents are vents for which the total organic HAP concentration is greater than or equal to 20 ppmv, and whose total VOC emissions are greater than or equal to 33 kg per day (75 lbs/day). Group 2 Process vents are vents that do not meet the definition of a Group 1 vent. Details of compliance requirements are in the Specific Conditions.

Miscellaneous process vent monitoring provisions are found at § 63.644, and test methods and procedures are found at §63.645. The CDU vacuum tower vent is introduced into the flame zone of the CDU H-2 Heater. The LEU T-1 hydrostripper vent is introduced into the flame zone of the LEU H-102 heater. Both vents are exempt from monitoring and performance testing requirements because they are directed into the flame zone of a boiler or process heater.

Equipment Leaks
EUG 8 is a grouping of all the Hazardous Air Pollutant (HAP) fugitive equipment component sources that exist in the refinery. Two compliance options are given at § 63.648, consisting of a modified 40 CFR 63, Subpart H method, and a modified 40 CFR 60, Subpart VV method. The HFTR Refinery currently chooses to follow the Subpart VV option. The 40 CFR 63 Subpart CC modifications to Subpart VV are primarily in applicability and component exemptions. Applicability is limited to components that contain equal to or more than 5% by weight HAP. Exemptions in addition to Subpart VV include wastewater system drains, storage tank sample valves, and tank mixers. Also, reciprocating pumps in light liquid service and reciprocating compressors are exempt from § 60.482 if recasting the distance pieces or new equipment is required. Subpart VV requires, among other things, leak detection and repair at valves in gas/vapor and light liquid service, and offers three options for such valves. The first is the main standard at § 60.482-7, which requires monthly monitoring unless the valve shows no leaks after two successive months after which the valve may be monitored quarterly until it indicates leakage. The second option is given at § 60.483-1, in which valves are tested initially, and then

annually or as requested by DEQ, and the percentage of leaking valves is not allowed to exceed 2%. The third option is given at § 60.483-2, in which good leak performance leads to skip periods of monitoring that leads to annual monitoring so long as leakers remain below 2%. The use of either of the second two options requires prior notification to DEQ. This facility currently follows the base procedures given at § 60.482-7, but requests alternative scenario status for the other two options since they represent another form of compliance measurement, and because they require notification to DEQ. Whether these scenarios will be used or not depends on the facility's analysis of the benefits of invoking them. At the present time these options are moot because OAC 252:100-39-15 requires quarterly monitoring of valves. If Section 39-15 is modified in the future to provide reduced monitoring after periods of continuous compliance, the facility will select the compliance option described in § 63.648(a)(2).

All Leak Detection and Repair (LDAR) reporting required by 40 CFR 60 Subpart GGG (semi-annual), and 40 CFR 63 Subpart CC (semi-annual) has been consolidated to simplify overlapping requirements. All LDAR reporting is included in the MACT semi-annual report covering all monitoring required from January 1st through June 30th and July 1st through December 31st. Reports are due 60 days after the end of each six month period per § 63.654(g).

Gasoline Loading Terminal
The West Refinery no longer loads gasoline.

Wastewater Streams and Treatment
Requirements for the wastewater system are defined at § 63.647 as equivalent to the provisions of 40 CFR 61, Subpart FF. Recordkeeping, reporting, and monitoring is also defined at § 63.654 to be what is required at § 61.356 and § 61.357. The facility is in compliance based on compliance with 40 CFR 61, Subpart FF.

Cooling Towers
Specifications for "Heat exchange system" have been added as 40 CFR Part 63.654. A facility is exempt from these standards if a cooling tower operates with a pressure difference of at least 5 psia between the cooling water side and process side, or employ an intervening cooling fluid with is less than 5% organic HAPs. Otherwise, the operator must perform monitoring to identify leaks and repair those leaks. There are separate standards for closed-loop systems and once-through systems.

Subpart DD (Off-Site Waste and Recovery Operations) Affected facilities are those that are major under 40 CFR 63.2 and process, recover, or recycle waste that is generated off-site and brought to the facility. The refinery processes no off-site waste. Any recovered material, regardless of processing, is generated on-site.

Subpart UUU (Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units) This MACT was issued April 11, 2002, and the compliance date for existing units was April 11, 2005. The Platformer (EUG 16) is the only process unit at the facility subject to this MACT. The facility submitted their initial notification of affected source on August 7, 2002. An analysis performed 9/25/02 through 9/28/02, during regeneration, demonstrated HCl levels below detectable levels, demonstrating that inorganic HAP emissions are below limitations discussed in § 63.1567 and listed at Table 22 of Subpart UUU. Options for compliance with organic HAP limits are discussed in § 63.1566. Any performance test must be performed and results submitted no more than 150 days after the compliance date (§ 63.1671). A performance test was conducted on March 11, 2005. The Notice of Compliance Status Report and the Operation, Maintenance, and Monitoring Plan were submitted on June 16, 2005.

Subpart ZZZZ (Reciprocating Internal Combustion Engines (RICE)) This subpart previously affected only RICE with a site-rating greater than 500 brake horsepower that are located at a major source of HAP emissions. On August 20, 2010, EPA published additional requirements for stationary SI RICE located at area and major sources. There are nine engines that are existing CI RICE and are subject to work practice standards. There are five existing SI RICE that are subject to emission limits. There are four emergency SI RICE that are subject to work practice standards. A summary of these proposed requirements for engines located at this facility is shown following. New standards published January 31, 2013, may change the applicable standards.

For each	You must meet the following requirement, except during periods of startup	During periods of startup you must
1. Emergency CI and black start CI.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
6. Emergency SI RICE and black start SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

11. Non-emergency, non-black start 4SRB stationary RICE 100 <HP<500.[1]	Limit concentration of formaldehyde in stationary RICE exhaust to 10.3 ppmvd or less at 15% O_2.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.
[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.
[3]Sources can petition the Administrator pursuant to the requirements of §63.6(g) for alternative work practices.

Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters) This subpart affects industrial, commercial and institutional boilers and process heaters at major sources of HAPs. "New" gas-fuel "1" units (which include RFG) are not subject to any emissions limits under Subpart DDDDD. Existing RFG-burning heaters and boilers smaller than 5 MMBTUH are not subject to any standards, while new and existing large gas-fueled heaters and boilers are subject only to requirements of an initial energy audit and periodic tune-ups. NESHAP does not have provisions for making an "existing" source subject to "new" source standards based on "modification."

Subpart GGGGG (Site Remediation) This subpart is applicable to facilities that conduct a site remediation which cleans up a remediation material at a facility that is co-located with one or more other stationary sources that emit HAP and meet the affected source definition. This facility is a major source of HAP and currently conducts site remediation at the facility.

Site remediation at a facility is not subject to this subpart, except for the recordkeeping requirements specified in § 63.7881(c), if the site remediation meets the all of the following conditions:

1. Before beginning the site remediation, you determine that for the remediation material to be excavated, extracted, pumped, or otherwise removed during the site remediation that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) is less than 1.10 TPY.
2. The facility prepares and maintains at the facility written documentation to support the determination of the total HAP quantity used to demonstrate compliance with § 63.7881(c)(1). The documentation must include a description of the methodology and data used for determining the total HAPs content of the material.

3. This exemption may be applied to more than one site remediation at the facility provided that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) for all of the site remediations exempted under this provision is less than 1.10 TPY.

This facility has documented that all of the site remediation at the facility totals less than 1.10 TPY and is only subject to the recordkeeping requirements of this subpart.

Compliance Assurance Monitoring, 40 CFR Part 64 [Applicable]
This part applies to any pollutant-specific emission unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses "large emissions units," or any application that addresses "large emissions units" as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY or 10/25 TPY of a HAP

Although there have been very few emission limits for sources in the refinery, many sources within the refinery are subject to the standards of 40 CFR 63 Subpart CC and UUU. Provisions for monitoring contained in these subparts is considered presumptively acceptable monitoring in accordance with § 64.4(b)(4). The required explanation of the applicability is found in the discussion for NESHAP's CC and UUU.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
Toxic and flammable substances subject to this regulation are present in the facility in quantities greater than the threshold quantities. A Risk Management Plan was submitted to EPA on June 1, 1999, and resubmitted as required by rule.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

This facility does not utilize any Class I & II substances in its refining processes.

SECTION XII. COMPLIANCE

Inspection
Full compliance evaluations (inspections) of the facility are performed regularly. The inspections are complicated, occur in segments, and are performed by various DEQ individuals.

Tier Classification and Public Review
This application has been classified as **Tier II** based on the request for a construction permit for a "significant" modification. The applicant published the "Notice of Filing Tier II Application" in *The Tulsa Business & Legal News* on July 3, 2017. A draft of this permit was also made available for public review for a period of 30 days as stated in another newspaper announcement on December 2, 2017, and on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*." The proposed permit was submitted to EPA for a 45-day review period. No comment were received from the public, but EPA Region VI provided several comments bearing on both East and West Refineries, listed following.

EPA COMMENT

Comments on the permit application:

1. *In the 26 June 2017 permit application No. 2012-1062-C (M-10)(PSD) for the East Refinery, the Baseline Actual Emissions Summary table (Attachment 2, pages 21-24) represents total NOx emissions from the East refinery as 262 TPY and includes two boilers (Boilers #3 and #4) that have baseline NOx emissions of 2.34 TPY and 4.88 TPY respectively. These same two boilers are identified in the Summary of Contemporaneous Project Emission Decreases and Increases (for the West Refinery) as "Removed" and a credit of 196 TPY is attributed to those sources (page 25). Please provide more details for the permit record supporting the company's (or ODEQ) analysis being applied in this action due to the large difference in the baseline actual emissions and credited emissions of 196 TPY.*

2. *Similarly, in the application Attachment 3 - Facility-Wide Projected Actual Emission Table includes emissions for the "removed" boilers (pages 27-28). Is this a typo?*

AQD RESPONSE

A considerable amount of confusion appears to have resulted from their being boilers designated "3" and "4" at both East and West Refineries. Boilers 3 and 4 at the West Refinery remained active, while Boilers 3 and 4 at the East Refinery were retired.

EPA COMMENT

Comments on Proposed Permit 2012-1062-C (M-10)(PSD):

3. *It is unclear in ODEQ's permitting record if this current 2017 action includes other previous minor-NSR revisions, encompasses other prior PSD permit actions, or supersedes previous actions. On the first page of the East Refinery draft/proposed permit Np. 2012-1062-C (M-10)(PSD), the Introduction references "six proposed changes to the two PSD permit (three at the West Refinery and three at the East Refinery)". However, in the actual application for the permit No. 2012-1062-C (M-10)(PSD), it appears only one project is included not three. Similarly, at the top of page 2 the permit intro talks about projects since 2014 to expand production at the refinery and "new process units". Again, it is unclear what project or projects are covered and whether prior permit actions are being brought forward in an effort to preclude NSR circumvention.*

AQD RESPONSE

The purpose of the current permit modification is to add projects which are related to the overall expansion as previously permitted. It appears that mentioning the numbers of related projects is causing confusion. We will remove the numbers to remove the confusion.

The projects proposed in these permit amendments are in addition to the existing projects authorized by the current permit that are in various stages of consideration, engineering and/or construction. These proposed modifications are:

- West – Addition of the West Residual Loading Rack, CDU life extension project, and MEK expansion project
- East - DHT heater increase, FCCU stack height change, temporary cooling tower addition

Therefore, Holly is required to include these additional changes as part of the overall "project" previously permitted by the original three construction permits. The PSD review is updated as required.

EPA COMMENT

4. *Please explicitly state the status of projects/actions from 2015 to present.*

   a. *The PSD permit references a modification to the CDU Atmospheric Heater (see also page 4) but no information on the increased rating and throughput is in the permit application No. 2012-1062-C (M-10)(PSD). Was this project covered in an earlier application or permit action?*

   b. *Similarly, the proposed permit references an expansion of the Continuous Catalytic Reforming Unit (CCR) with no related information in the PSD permit application (pages 6-7).*

   c. *The permit references a "new ROSE Unit" to be constructed at the East Refinery (p. 11).*

   d. *In Section III – Proposed Project Descriptions (permit pages 13- 14), none of the projects are included in the M-10 application.*

AQD RESPONSE

There are four items in the EPA comment:

Yes, the original project included modifying the CDU heater to increase the capacity. That change was included in the original PSD review and this updated evaluation. As per the previous response, Holly is updating the original project based on proposed changes to the expansion project. Holly is now including the CDU tower external shell project.

The added 25 MMBTUH heater is mentioned at the bottom of Page 7 of the evaluation and as part of the list of proposed projects on page 13.

The ROSE Unit was part of the earlier PSD permits issued for this project. Since it was already addressed, it is mentioned only in passing for a permit which is primarily for new projects and changes to the evaluations caused by those added projects.

The projects were all included in the original construction permits. This action "modifies" the PSD construction permits to address additional items that will occur as part of the overall "project." Therefore, Holly is required to modify the PSD construction permits.

EPA COMMENT

5. *Please provide more details for the permit record to support and/or clarify how the prior projects and the current permit modification are represented in the emissions provided in the application(s). Further, expanded discussion of the baseline emissions is also encouraged for purposes of clarity.*

   a. *The proposed permit still includes Boilers #3 and #4, which were represented in the netting discussion as "removed" (permit page 16). The "removed" boilers appear to still be included in the permit on page 31 under the heading of EUG 8, Fired Boilers. The discussion and table clearly reference "Four Boiler Total" emissions, and the permit specifically limits the NOx emissions from the four boilers to 122 TPY.*

   b. *What is the purpose of the "Facility-Wide Emissions Totals" on page 41 of the permit? It is unclear from the narrative what relevance emissions from the "original" renewal have for this permit modification. What relevance do 2006 emissions have and are they acceptable for a 2017 permit action?*

   c. *The "Net Emissions Changes" discussion on pages 42-43 states that Boilers 3 and 4 are at the West Refinery rather than the East: is that a typographic error?*

   d. *The "Baseline Actual Emissions" table on page 44 includes NOx emission for Boilers 3 and 4 at the East Refinery as 2.34 TPY and 4.88 TPY respectively. However, in the "Post-Project Potential to Emit for NOx, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG / SO2 Projected Actual Emissions" table on page 46 the same boilers both are listed as a PTE for NOx of 30.6 TPY. Should theses boilers have zero PTE post-project if they have been removed?*

   e. *In the subsequent PSD Netting table on pages 49, Boilers 3 and 4 are listed ~~as~~ at the West refinery, which doesn't appear to be accurate.*

   f. *It is also unclear in the permit record how the removal of the two boilers with actual baseline emissions of less than eight tons per year and a potential to emit of approximately 62 tons per year would produce a reduction of 196 TPY NOx. We encourage ODEQ provide additional support in its permit record documenting the netting analysis.*

AQD RESPONSE

The emissions changes from the prior projects are unchanged from the previous permit;_only the new items have emissions revised. Emissions calculations for those projects are included in the permit evaluation

There were six additional items in this comment:

a. This is part of the confusion mentioned earlier about having boilers designated "3" and "4" at both East and West Refineries. Only those boilers 3 and 4 at the West Refinery have been retired; the boilers at the East Refinery remain in service.

b. This was general information provided to give a reasonable description of potential facility emissions. The "Facility-Wide Emissions Totals" was removed.

c. This is another location where having Boilers 3 and 4 at both East and West Refineries caused confusion.

d. Similar confusion for having Boilers 3 and 4 at both East and West Refineries appeared to trigger this comment.

e. Boilers 3 and 4 at the East Refinery will remain active.

f. Here again, the confusion resulted from having Boilers 3 and 4 at both East and West Refineries.

EPA COMMENT

6. *The BACT analysis discussion is confusing and doesn't appear related to the increased firing rate of the DHTU heater that was in the M-10 permit application. Please provide more details and/or BACT discussion for the increased firing rate of the DHTU unit as it relates to the permit application No. 2012-1062-C (M-10)(PSD).*

AQD RESPONSE

The capacity of the DHTU Heater in question was stated inaccurately in the past (55 MMBTUH instead of 80 MMBTUH). It is not being physically modified, but the inaccurately-stated capacity would yield inaccurate emissions and resultant ambient impacts. It is not subject to BACT.

EPA COMMENT

B. Air Quality Impacts Evaluation: HollyFrontier Tulsa Refining, LLC – East and West Refineries

7. *In the "Control Parameters" discussion found in the Evaluation of Air Quality Impacts and Determination of Monitoring Requirements section of both draft permits (Permit Nos. 2010-599-C (M-8)(PSD) and 2012-1062-C (M-10)(PSD)), the OLM modeling approach is referenced as a "non-regulatory default" model option. As part of the recent revisions to Appendix W (effective May 22, 2017), OLM is now a regulatory option. We understand that the permit review was conducted during the transition period of the Appendix W revisions, but as discussed with ODEQ modeling*

contacts during a call on January 18, 2018 we suggest that the permit record be updated to reflect the current status of the OLM model option.

AQD RESPONSE

The Permit Memorandum has been updated to remove references to the Tier 3 modeling approach using OLM as a non-regulatory default option.

EPA COMMENT

8. *In the "Evaluation of Class I Area Impacts" discussion found in the Other PSD Analyses section of both draft permits (Permit Nos. 2010-599-C (M-8)(PSD) and 2012-1062-C (M-10)(PSD)), the CALPUFF model, which was used in the Tier II Class I significance modeling analysis, is referenced as being "the EPA-recommended model for estimating concentrations at distances greater than 50 km". As part of the recent revisions to Appendix W (effective May 22, 2017), CALPUFF was removed from being a preferred model in Appendix A for long-range transport assessments. As discussed with ODEQ modeling contacts during a call on January 18, 2018, we believe that the use of CALPUFF as a screening technique remains appropriate in this case and suggest that the reference to the usage of CALPUFF within the permit record be updated to reflect its current status as a potential screening approach.*

AQD RESPONSE

The Permit Memorandum has been updated to reflect that CALPUFF can be used as a screening model for estimating impacts for long-range transport. Due to a correction of the $PM_{2.5}$ Class I area significant impact levels, the CALPUFF Class I area modeling analysis was no longer needed and was removed from the Permit Memorandum.

EPA COMMENT

9. *The "Background Concentrations" discussion found in the Evaluation of Air Quality Impacts and Determination of Monitoring Requirements section of both draft permits (Permit Nos. 2010-599-C (M-8)(PSD) and 2012-1062-C (M-10)(PSD)) indicates that as part of an NO_2 modeling refinement, hour-by-hour background NO_2 concentrations from the Tulsa monitor were used in the cumulative analysis. It is not clear in the draft permit, if this refinement is consistent with current EPA policy and guidance on background concentrations allowing for seasonal and/or hour by day background concentrations or if a true hour-by-hour ("paired sums") approach was used. During our discussion with ODEQ on January 18, 2018, modeling staff clarified that EPA guidance was followed in developing the background concentration refinement and a "paired sums" approach was not used. We suggest that the permit record be updated to include this clarification regarding the NO_2 modeling refinements.*

AQD RESPONSE

In the "Class II Area Dispersion Modeling Approach by Pollutant/NO_2 Modeling Approach" section it states that the AQD provided the 98th percentile hourly, processed on a Seasonal, Hour-of-Day and Day-of-Week basis from the North Tulsa monitor (40-143-1127). However, similar wording was added to the "Background Concentrations" section of the Permit Memorandum. The Permit Memorandum has been updated to clarify that a paired sums approach was not used.

EPA COMMENT

10. *In the "Full Impact Analyses" discussion found in the Evaluation of Air Quality Impacts and Determination of Monitoring Requirements section of both draft permits (Permit Nos. 2010-599-C (M-8)(PSD) and 2012-1062-C (M-10)(PSD)), the permit record provides information regarding modeled potential NAAQS violations along with a tabular listing of the maximum NAAQS impact at violating receptors, paired with the corresponding project contribution in time and space. As part of contribution analysis, each of the modeled violations, and not just the maximum impacts, should be examined to determine if a source/project significantly contributes a modeled violation. Based on our discussion with ODEQ modeling contacts on January 18, 2018, we understand that each of the violations were examined to determine that the project was not significant to any of the modeled violations. We suggest updating the record to clearly state that each of the modeled violations were examined as part of the contribution analysis.*

AQD RESPONSE

The Permit Memorandum was updated to include wording that clearly indicates that each of the potential modeled violations were examined and the project did not have a significant contribution at any of them.

EPA COMMENT

11. *Based on our review of the permit memorandum for Draft Permits Nos. 2010-599-C (M-8)(PSD) and 2012-1062-C (M-10)(PSD), it appears that at least a portion of the discussion contained in the Evaluation of Air Quality Impacts and Determination of Monitoring Requirements section of the draft permits is carried over from the 2015 permit modification of those permits. As discussed in our January 18, 2018 call with ODEQ modeling contacts, we suggest that the current permit record be updated to clarify what information is included as historical reference from the 2015 permit action and what information is specifically updated and included to support the current permit action. In addition, we suggest that the 2015 reference information be revised to reflect the final permit record for that permit action, accounting for the public comments received and responses to those comments provided by ODEQ in 2015.*

AQD RESPONSE

An introduction section was added to the Evaluation of Air Quality Impacts and Determination of Monitoring Requirements section of the Permit Memorandum to address information incorporated since the issuance of the original PSD construction permit on April 20, 2015, and includes references to updates in the modeling guidelines issued since then. This section specifically references the EPA comments and the AQD responses to EPA comments related to the original PSD construction permit. In addition, where applicable, within the modeling section, additional references to the EPA comments and AQD responses to EPA comments from the original PSD construction permit were included.

This facility is not located within 50 miles of the border with a contiguous state.

Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page: www.deq.state.ok.us/.

Fee Paid
Major source construction permit fee of $5,000

SECTION XIII. SUMMARY

The facility has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. Ambient air quality standards are not threatened at this site. Issuance of the permit is recommended.

SCOTT A. THOMPSON
Executive Director

OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

MARY FALLIN
Governor

FEB 13 2018

Andrew Haar, Environmental Manager
HollyFrontier Tulsa Refining – Tulsa LLC
1700 S. Union
Tulsa, OK 74107

Re: Permit No. 2010-599-C (M-8)(PSD)\
Expansion of Tulsa Refinery
Tulsa Refinery West

Dear Mr. Haar:

Enclosed is the modified permit authorizing construction of the referenced facility. Please note that this permit is issued subject to the standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at (405) 702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact me at david.schutz@deq.ok.gov or (405) 702-4198.

Sincerely,

David S. Schutz

David S. Schutz, P.E.
New Source Permits Section
Air Quality Division

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2010-599-C (M-8)(PSD)

HollyFrontier Tulsa Refining – Tulsa LLC,

having complied with the requirements of the law, is hereby granted permission to modify the Tulsa Refinery West, at 1700 S. Union, Tulsa, Tulsa County, Oklahoma,

subject to the following Standard Conditions dated June 21, 2016, and Specific Conditions, both attached.

In the absence of commencement of construction, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

Division Director **Air Quality Division**	2-7-18 **Date**

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

HollyFrontier Tulsa Refining – Tulsa LLC **Permit Number 2010-599-C (M-8)(PSD)**
HFTR Tulsa Refinery West

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on June 27, 2014. The Evaluation Memorandum dated February 5, 2018, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

SPECIFIC CONDITION 1 **[OAC 252:100-8-6(a)]**

The permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following conditions. Records necessary to show compliance with each of the requirements below must be maintained. [OAC 252:100-8-6(a)(1)]

a. EUG Plant-Wide: Certain equipment within the refinery is subject to 40 CFR 63 Subpart CC and all affected equipment shall comply with all applicable requirements. Requirements listed in previous EUGs are not repeated here. [40 CFR 63 Subpart CC]

   1. § 63. 63.642 General Standards
   2. § 63.643 Miscellaneous Process Vent Provisions
   3. § 63.644 Monitoring for Miscellaneous Process Vents
   4. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
   5. § 63.654 Reporting and Recordkeeping Requirements
   6. The permittee shall comply with the provisions of 40 CFR 63 Subpart A as specified in Appendix to Subpart CC, Table 6.

b. Various asbestos renovation and demolition projects at the Tulsa Refinery are subject to State and Federal standards, including:

   1. The federal standards found in 40 CFR 61 Subpart M. [40 CFR § 61.145]
   2. The following requirements for handling asbestos are in addition to those listed in the asbestos NESHAP, 40 CFR 61 Subpart M. [OAC 252:100-40-5]

      A. Before being handled, stored or transported in or to the outside air, friable asbestos from demolition/renovation operations shall be double bagged in six-mil plastic bags, or single bagged in one six-mil plastic bag and placed in a disposable drum, or contained in any other manner approved in advance by the AQD Director.
      B. When demolition/renovation operations must take place in the outdoor air, friable asbestos removed in such operations shall be immediately bagged or contained in accordance with (A).

C. Friable asbestos materials used on pipes or other outdoor structures shall not be allowed to weather or deteriorate and become exposed to, or dispersed in the outside air.
D. Friable asbestos materials shall, in addition to other provisions concerning disposal, be disposed of in a facility approved for asbestos by the Solid Waste Management Division of DEQ.

c. The following procedures are required for any process unit shutdown, purging, or blowdown operation. [OAC 252:100-39-16]

1. Recovery of VOC shall be accomplished during the shutdown or turnaround to a process unit pressure compatible with the flare or vapor system pressure. The unit shall then be purged or flushed to a flare or vapor recovery system using a suitable material such as steam, water or nitrogen. The unit shall not be vented to the atmosphere until pressure is reduced to less than 5 psig through control devices.
2. Except where inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline," or any State of Oklahoma regulatory agency, no person shall emit VOC gases to the atmosphere from a vapor recovery blowdown system unless these gases are burned by smokeless flares or an equally effective control device as approved by the Division Director.
3. At least fifteen days prior to a scheduled turnaround, a written notification shall be submitted to the Division Director. As a minimum, the notification shall indicate the unit to be shutdown, the date of shutdown, and the approximate quantity of VOC to be emitted to the atmosphere.
4. Scheduled refinery unit turnaround may be accomplished without the controls specified in (a) and (b) during non-oxidant seasons provided the notification to the Division Director as required in (c) specifically contains a request for such an exemption. The non-oxidant season is from November 1 through March 31.

d. Non-condensable VOC from surface condensers and accumulators in the CDU vacuum producing system shall be vented to a heater firebox. [OAC 252:100-39-17]

e. Cold metal-cleaning units using any VOC shall comply with the following requirements.
   1. Mechanical design. The unit shall have a cover or door that can be easily operated with one hand, and shall have an internal drain board allowing lid closure or an external drain facility if the internal option is not practical. The unit shall have a permanently attached conspicuous label summarizing the operating requirements. [OAC 252:100-39-42(a)(1)]
   2. Operating requirements. All clean parts shall drain for at least 15 seconds or until dripping ceases before removal, the degreaser cover shall be closed when not handling parts, and VOC shall be sprayed only in a solid fluid stream, not in an atomized spray. Waste VOC shall be stored in covered containers and waste VOC shall not be handled in such a manner that more than 20% by weight can evaporate. [OAC 252:100-39-42(a)(2)]
   3. If the VOC used has vapor pressure greater than 0.6 psia or if the VOC is heated to 248 °F, the unit requires additional control. Such control shall be a freeboard with ratio at least 0.7, a water cover where the VOC is insoluble in and denser than water, or another system of equivalent control as approved by the AQD Director. [OAC 252:100-39-42(a)(3)]

f. A startup, shutdown, and malfunction plan has been prepared by HFTR in compliance with 40 CFR 63 Subpart A. The current plan shall be retained for the life of the facility and superseded versions of the plan shall be retained for five years after the date of revision. Both current and retained versions shall be readily available for review. [40 CFR 63.6(e)(3)]

g. VOC storage vessels greater than 40,000 gallons in capacity and storing a liquid with vapor pressure greater than 1.5 psia shall be pressure vessels or shall be equipped with one of several vapor loss control systems. [OAC 252:100-37-15(a)]

h. Activities at EUG 18 have established that HFTR is subject to 40 CFR 63 Subpart GGGGG. Any and all other activities at HFTR that are "site remediations" as defined in § 63.7957 and satisfy the requirements of §63.7881(a), unless otherwise exempted, shall comply with any applicable requirements, including, but not limited to: § 63.7880 - 7883 What This Subpart Covers
   1. § 63.7884 - 7888 General Standards
   2. § 63.7890 - 7893 Process Vents
   3. § 63.7895 - 7898 Tanks
   4. § 63.7900 - 7903 Containers
   5. § 63.7920 - 7922 Equipment Leaks
   6. § 63.7935 - 7938 General Compliance Requirements
   7. § 63.7950 - 7953 Notifications, Reports, and Recordkeeping
   8. § 63.7955 - 7957 Other Requirements and Information
   9. The permittee shall comply with the provisions of 40 CFR 63 Subpart A as specified in Appendix to Subpart GGGGG, Table 3.

i. Per OAC 252:100-8-36-(c), records shall be kept comparing actual emissions from units in the Refinery Integration project with projected actual emissions. As part of the operating permit application, the storage tanks for gasoline, distillates and naphthas affected by this project shall be identified.

SPECIFIC CONDITION 2

Standards for affected Emission Unit Groups (EUG). [OAC 252:100-8-6(a)]

EUG 1: Existing Refinery Fuel Gas Burning Equipment

Const. Date	EU	Point ID
1957	210	#2 Plat PH-3
1961	201N	CDU H-1,N,#7
1961	201S	CDU H-1,S,#8
1957	206	Unifiner H-2
1957	207	Unifiner H-3

Const. Date	EU	Point ID
1956	238	PDA B-30
1962	240	PDA B-40
1963	242	LEU H101
1963	244	LEU H-201
1960	246	MEK H-2

CDU H-1 has two stacks, H-1 North and H-1 South.

a. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG 1A: Modified Refinery Fuel Gas Burning Equipment & Potential to Emit (PTE)

Constr. Date	MFR, BTUH, MM	EU	Point ID	NOx		CO		PM_{10}		SOx		VOC	
				lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1957	44.8	211	#2 Plat PH-4	4.48	19.62	3.76	16.48	0.34	1.49	1.16	1.92	0.25	1.08

a. The above unit is subject to New Source Performance Standards (NSPS), Subpart Ja and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Ja]
   1. § 60.102a Emission limitations;
   2. § 60.103a Work practice standards as applicable;
   3. § 60.104a Performance tests as applicable;
   4. § 60.107a Monitoring of operations – (a)(2), (3), and (4); and
   5. § 60.108a Recordkeeping and reporting requirements.

b. The above unit shall only be fired with Subpart Ja compliant refinery fuel gas or pipeline-grade natural gas. The boiler shall be equipped with a fuel gas meter. [40 CFR Part 60, Subpart Ja, OAC 252:100-8-6(a)(1)]

c. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. [OAC 252:100-19-4]

EUG 2: Non-Grandfathered Boilers

CD	EU	Point ID	CO		NOx		PM_{10}		SOx		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1975	109	#7 Boiler, 150 MFR	12.6	55.2	30.00	131.4	1.12	4.90	3.90	17.08	0.83	3.62
1976	110	#8 Boiler, 150 MFR	12.6	55.2	30.00	131.4	1.12	4.90	3.90	17.08	0.83	3.62
1976	111	#9 Boiler, 150 MFR	12.6	55.2	30.00	131.4	1.12	4.90	3.90	17.08	0.83	3.62

a. Nitrogen oxides emissions shall not exceed 0.20 lb/MMBTU (3-hr average). [OAC 252:100-33-2(a)]

b. All fuel-burning or refuse-burning equipment shall be operated to minimize emissions of VOC. Among other things, such operation shall assure based on manufacturer's data and good engineering practices, that the equipment is not overloaded; that it is properly cleaned, operated, and maintained; and that temperature and available air are sufficient to provide essentially complete combustion. [OAC 252:100-37-36]

c. All boilers are subject to 40 CFR 60 Subpart J, and shall comply with all applicable provisions. [40 CFR 60, Subpart J]

d. At least once during the term of the operating permit, the permittee shall conduct performance testing of NOx emissions from each boiler and furnish a written report to Air Quality. [OAC 252:100-43]

e. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG 2A: Boiler Subject to NSPS Subparts Db and Ja

Point ID	NOx		VOC		PM_{10}		CO		SO_2	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
#10 Boiler	12.88	39.0	1.18	5.17	1.63	7.16	18.1	79.10	5.59	9.23

All lb/hr emission limits on a 3-hour rolling average, based on 1 hour blocks.

a. The boiler is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Db, and shall comply with all applicable requirements, including, but not necessarily limited to those conditions shown following. (NOTE: Permit limitations are more stringent than Db limitations and will result in compliance with Subpart Db.) [40 CFR 60.40b through 60.49b]

   1. The boiler shall not discharge into the atmosphere any gases that contain nitrogen oxides (expressed as nitrogen dioxide) in excess of 0.20 lbs/MMBTU, 3-hour rolling average, based on 1-hour blocks. [40 CFR 60.44b(a)(1)(ii)]
   2. § 60.46b Performance test and compliance provisions;
   3. § 60.48b Emission Monitoring, and
   4. § 60.49b Reporting and recordkeeping requirements.

b. The above unit is subject to New Source Performance Standards (NSPS), Subpart Ja and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Ja]
   1. § 60.102a Emission limitations;
   2. § 60.103a Work practice standards as applicable;
   3. § 60.104a Performance tests as applicable;
   4. § 60.107a Monitoring of operations; and
   5. § 60.108a Recordkeeping and reporting requirements.

c. The above unit shall only be fired with Subpart Ja compliant refinery fuel gas or pipeline-grade natural gas. The boiler shall be equipped with a fuel gas meter. [40 CFR Part 60, Subpart Ja, OAC 252:100-8-6(a)(1)]

d. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. [OAC 252:100-19-4]

e. The facility shall maintain records of the amount of fuel combusted in the boiler and fuel heating value, daily. The facility shall also maintain records of NOx emissions (monthly) calculated from fuel heating value (BTU/SCF), fuel usage (SCFD), and monitored NOx emission rates (lb/MMBTU). [OAC 252:100-8-34(b)]

f. Compliance with the PM, VOC and CO emission limits shall be via initial performance test. [OAC 252:100-8-6(a)]

EUG 3: #2 Plat PH-5 Heater.

In the event of conflict between limits set by permit or by regulation, the more stringent limit shall apply.

#2 PLAT PH-5 HEATER (AUTHORIZED EMISSIONS IN TPY) Subject to NSPS J

CD	EU	Point ID	CO	NOx	PM_{10}	SOx	VOC
1990	212	#2 Plat PH-5 65.3 MMBTU/hr	23.55	28.04	2.13	7.43	1.54

a. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. [OAC 252:100-19-4]

b. Sulfur oxide emissions (calculated as sulfur dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.2 lbs/MMBTU heat input (86 ng/J), three-hour average. [OAC 252:100-31-25(a)(1)]

c. Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBTU (86 ng/J) heat input, three-hour average. [OAC 252:100-33-2(a)]

d. Operator is permitted to burn #2 Platformer absorber tower offgas, commercial natural gas, or NSPS Subpart J Refinery Fuel Gas in PH-5. Fuel gas shall not contain hydrogen sulfide in excess of 230 mg/dscm (0.1 gr/dscf).

e. The above unit is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]

f. When burning #2 Platformer absorber tower offgas or commercial natural gas, PH-5 is not required to meet the monitoring requirements in 40 CFR §§60.105(a)(3) and 60.105(a)(4) because it meets the exemptions in 40 CFR §§60.105(a)(4)(iv)(B)&(C).

EUG 3A: #2 Plat PH-6 Heater.

In the event of conflict between limits set by permit or by regulation, the more stringent limit shall apply.

#2 PLAT PH-6 HEATER (AUTHORIZED EMISSIONS IN TPY)

CD	EU	Point ID	CO	NOx	PM_{10}	SOx	VOC
1957	213	#2 Plat PH-6 34.8 MMBTUH	12.55	14.94	1.14	3.96	0.82

EUG 4: Coker H-3 Heater

EU 24	Pollutant	Authorized Emissions	
		lb/hr	TPY
Coker H-3 32.2 MMBTUH, constructed 1995	SO_2	0.84	1.38
	NO_X	3.22	14.10
	VOC	0.18	0.78
	CO	2.70	11.85
	PM	0.25	1.07

The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

[OAC 252:100-19-4]

a. The above unit is subject to New Source Performance Standards (NSPS), Subpart Ja and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Ja]
   1. § 60.102a Emission limitations;
   2. § 60.103a Work practice standards as applicable;
   3. § 60.104a Performance tests as applicable;
   4. § 60.107a Monitoring of operations – (a)(2), (3), and (4); and
   5. § 60.108a Recordkeeping and reporting requirements.
b. The above unit shall only be fired with Subpart Ja compliant refinery fuel gas or pipeline-grade natural gas. The boiler shall be equipped with a fuel gas meter.
   [40 CFR Part 60, Subpart Ja, OAC 252:100-8-6(a)(1)]
c. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.
   [OAC 252:100-19-4]

EUG 5: Coker B-1 Heater, Constructed 1992 Subject to NSPS J and 40 CFR 63 Subpart DDDDD

CD	EU	Point ID	CO		NOx		PM_{10}		SO_2		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1992	225	Coker B-1, 60 MFR	5.04	22.08	6.00	26.28	0.46	2.00	5.85	25.63	0.33	1.45

a. The above unit is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions.
b. The above unit shall be fired with NSPS Subpart J compliant refinery fuel gas or pipe-line grade natural gas.
c. Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J) heat input, three-hour average. [OAC 252:100-33-2(a)]
d. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG 6: MEK H-101 Heater, Constructed 1977 Subject to NSPS Subpart J and 40 CFR 63 NESHAP DDDDD

Pollutant	Limit (Lbs/MMBtu)
PM_{10}	0.37
SO_2	0.20
NO_X	0.20

a. The above unit is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions.

b. The above unit shall only be fired with refinery fuel gas or pipeline-grade natural gas. [OAC 252:100-8-6(a)(1)]

c. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

d. Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lb/MMBtu (86 ng/J) heat input, three-hour average. [OAC 252:100-33-2(a)]

EUG 7: Refinery Fugitive Emissions Subject to NSPS

40 CFR 60.590 (Subpart GGG): LEU and Perc Filter

a. The facility shall comply with the following applicable requirements of 40 CFR 60 Subpart GGG.

1. The operator shall comply with the applicable requirements referenced in Subpart VV at §§60.482-2 to 60.482-10. [§ 60.592(a)]
2. The operator shall comply with the provisions of Subpart VV § 60.485, except as provided in §60.593. [§ 60.592(d)]
3. The operator shall comply with the provisions of Subpart VV § 60.486. [§ 60.592(e)]
4. The operator shall comply with the provisions of Subpart VV § 60.487. The operator shall submit Semiannual Reports no later than 60 days after January 1st and July 1st of each year. [§ 60.592(e)]

40 CFR 60.590a (Subpart GGGa): Flare Gas Recovery Unit, ROSE Unit (formerly PDA), MEK Unit, and New Hydrogen Plant

a. The facility shall comply with the following applicable requirements of 40 CFR 60 Subpart GGGa.

1. The operator shall comply with the applicable requirements referenced in Subpart VVa at §§60.482-2a to 60.482-10a. [§60.592a(a)]
2. The operator shall comply with the provisions of Subpart VVa §60.485a, except as provided in §60.593a. [§60.592a(d)]
3. The operator shall comply with the provisions of Subpart VV §60.486a. [§60.592a(e)]
4. The operator shall comply with the provisions of Subpart VV §60.487a. The operator shall submit Semiannual Reports no later than 60 days after January 1st and July 1st of each year. [§60.592a(e)]

EUG 8: Refinery Fugitive Emissions Subject to 40 CFR 63.640 (Subpart CC) (#2 Platformer, Coker, CDU, Truck Loading Dock, Tank Farm, Unifiner)

a. The facility shall comply with the following applicable requirements of 40 CFR 63 Subpart CC.
   1. Per paragraph (a), the operator of an existing source subject to the provisions of this subpart shall comply with the applicable provisions of 40 CFR 60 Subpart VV and paragraph (b) of §648 except as provided in subparagraphs (a)(1), (a)(2), and paragraphs (c) through (i) of §648. Subparagraphs (a)(1) and (a)(2) provide that VV applies only to equipment in HAP service and that the calculation method may not be changed except through permit action. Paragraph (c) allows compliance with Subpart H standards in lieu of VV standards under certain circumstances. Paragraphs (d) and (e) define the applicability of Subpart H standards to pumps and valves, paragraph (g) exempts compressors in hydrogen service from the requirements of (a) and (c), and paragraphs (f) and (i) exempt pumps and compressors from certain requirements if replacement of the affected facility or recasting the distance piece is necessary. [§63.648]
   2. The operator shall comply with the recordkeeping provisions in paragraph (d)(1) through (d)(6) of §654. The operator shall comply with the provisions of §60.486. [§63.654(d)]
   3. The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche. [§63.642(e)]
   4. The operator shall comply with the reporting provisions in paragraph (d)(1) through (d)(6) of §654. The operator shall comply with the provisions of §60.487. The operator shall submit Periodic Reports no later than 60 days after January 1st and July 1st of each year. [§63.654(d)]

EUG 9: Refinery Fugitive Emissions Subject to OAC 252:100-39-15

a. The refinery is subject to OAC 252:100-39-15 and shall comply with the applicable provisions,
   1. §39-15(b)(2) The operator shall maintain a Leak Detection and Repair Program (LDAR) for all components that have the potential to leak VOCs with a vapor pressure greater than or equal to 0.3 kPa (0.0435 psia) under actual storage conditions.
   2. §39-15(e). Testing and calibration procedures;
   3. §39-15(f) Monitoring;.
   3. §39-15(g) Monitoring log.
   4. §39-15(h) Reporting.

EUG 11: Lube Extraction Unit (LEU) and Coker Flare Subject to 40 CFR 60, Subparts GGG and Ja

EU	Point ID	Equipment	Date Installed
269	LEU Flare	John Zink EEF-QS-SA-18 smokeless flare tip	1976
268	Coker Flare	John Zink EEF-QS-30 smokeless flare tip	--

a. These flares shall comply with the applicable requirements of New Source Performance Standards A and GGG.
   1. The flare shall be operated with a pilot flame present at all times. [§60.18(c)(2)]
   2. The flare shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [§60.18(c)(1)]
   3. The flare shall be used only when the net heating value of the gas being combusted is 300 Btu/scf or greater. [§60.18(c)(3)(i)(B)(ii)]
   4. The operator shall ensure that the flare is operated and maintained in conformance with its design. [§60.18(d)]
   5. Steam-assisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR §60.18(f)(4), less than 60 ft/sec, except as provided below. [§60.18(c)(4)(i)]
      A. Steam-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in Paragraph d (see #05 above), equal to or greater than 60 ft/sec but less than 400 ft/sec are allowed if the net heating value of the gas being combusted is greater than 1,000 Btu/scf.
      B. Steam-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR §60.18(f)(4), less than the velocity, Vmax, as determined by the method specified in 40 CFR §60.18(f)(5), and less than 400 ft/sec are allowed.

b. The above units are subject to New Source Performance Standard Subpart Ja.
c. The flare shall comply with the provisions of NSPS General Provisions and in accordance with a DEQ approved alternative test method (ATM), Gary Keele, DEQ attorney, dated 12/20/96. The ATM required Sunoco (HFTR) to document calculations based on records under §60.486(d) for: [§60.486(d)]

1. the design specification of the flare to show it will operate smokeless;
2. the calculated maximum exit velocity of the flare based on the design criteria; and
3. the calculated net heating value of the gas relieved to the flare shall be based on the simulated composition of the gas. The requirements of this ATM were fulfilled on December 1, 1998.

EUG 11a: Platformer Flares Subject to 40 CFR 60, Subpart Ja

EU	Point ID	Equipment
267	Plat Flare	John Zink EEF-QS-30 smokeless flare tip

a. § 60.18(f)(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
b. The Platformer Flare is subject to NSPS, Subpart Ja, by November 11, 2014 it shall comply with all applicable provisions of NSPS, Subpart Ja, including but not limited to:

[40 CFR Part 60, Subpart Ja]

1. § 60.102a Emissions limitations;
2. § 60.103a Work practice standards;
3. § 60.104a Performance tests;
4. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
5. § 60.108a Recordkeeping and reporting requirements.

EUG 12: Wastewater Processing System Subject to 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC

EU	Point ID	Equipment	Installed Date
15943	WPU-1	Wastewater Processing Unit and Open Sewers 1. Headworks 2. Storm water Diversion Tank 1039 3. Primary Clarifier 4. North / South DAF 5. Cooling Towers 6. Equalization Basis 7. Aeration Basin 8. North/South Secondary DAF 9. Aerobic Digester 10. East/West Firewater Basin 11. Solid Waste Recovery (Centrifuge) 12. Slop Oil Recovery 13. East/West Storm Water Basin	Various

a. The facility shall meet the applicable requirements of 40 CFR 63 Subpart CC (Petroleum Refineries) and 40 CFR 61 Subpart FF (Benzene Waste). For facilities with a total annual benzene (TAB) quantity from waste operations falling between 1 and 10 megagrams, compliance with the requirements of FF satisfies the requirements of CC. The Tulsa refinery reports a TAB in this range.
b. The refinery is subject to NESHAP, 40 CFR 61, Subpart FF and shall comply with all applicable requirements. [40 CFR 61, NESHAP, Subpart FF]
   1. § 61.342 Standards: General.
   2. § 61.343 Standards: Tanks.
   3. § 61.344 Standards: Surface Impoundments.
   4. § 61.345 Standards: Containers.
   5. § 61.346 Standards: Individual drain systems.
   6. § 61.347 Standards: Oil-water separators.
   7. § 61.348 Standards: Treatment processes.
   8. § 61.349 Standards: Closed-vent systems and control devices.
   9. § 61.350 Standards: Delay of repair.
   10. § 61.351 Alternative standards for tanks.
   11. § 61.352 Alternative standards for oilwater separators.
   12. § 61.353 Alternative means of emission limitation.
   13. § 61.354 Monitoring of operations.
   14. § 61.355 Test methods, procedures, and compliance provisions.
   15. § 61.356 Recordkeeping requirements.
   16. § 61.357 Reporting requirements.
c. These records will be maintained in accordance with the recordkeeping requirements under 40 CFR § 61.356.
d. These reports will be maintained in accordance with the reporting requirements under 40 CFR § 61.357.

EUG 14: Group 1 Process Vents Subject to 40 CFR 63, Subpart CC

EU	Equipment Point ID	Control Device
N/A	CDU Vacuum Tower Vent	CDU H-2 Heater
N/A	LEU T-201 Hydrostripper Tower Vent	LEU H-102 Heater
N/A	Coker Enclosed Blowdown Vent	Platformer Flare, Coker Flare

a. The above vents are subject to 40 CFR 63 Subparts A and CC.
   1. § 63.642 (e) General standards;
   2. § 63.643 (a) and (b) Miscellaneous process vent provisions;
   3. § 63.644 (a) and (c) Monitoring provisions for miscellaneous process vents; and,
   4. § 63.645 Test methods and procedures for miscellaneous process vents.
   5. § 63.11 (b) Flares

EUG 15: Group 2 Process Vents Subject to 40 CFR 63, Subpart CC

EU	Equipment Point ID	Control Device
N/A	MEK T-7 Vent	NA
N/A	LEU-T101 Vent	NA
N/A	LEU D-101 Vent	NA
N/A	MEK Flue Gas Oxygen Vent	NA
N/A	MEK Knockout Drum O-52	LEU Flare

a. The above vents are subject to 40 CFR 63 Subparts A and CC.
   1. § 63.640 Applicability and designation of affected sources;
   2. § 63.643 (a) and (b) Miscellaneous process vent provisions;
   3. § 63.644 (a) and (c) Monitoring provisions for miscellaneous process vents; and
   4. § 63.645 Test methods and procedures for miscellaneous process vents .

EUG 16: Process Vent Subject to 40 CFR 63, Subpart UUU

EU	Equipment	Control Device
N/A	#2 Platformer Catalytic Reforming Vent	NA

a. The operator shall not exceed the emissions of hydrogen chloride listed in Table 22 of NESHAP, Subpart UUU. [§ 63.1567(a)(1)]
b. The operator shall meet the site specific operating limits in Table 23 of NESHAP, Subpart UUU. [§ 63.1567(a)(2)]
c. The unit shall be operated at all times in accordance with the procedures in the operation, maintenance, and monitoring (OMM) plan submitted pursuant to the requirements of §63.1574(f). [§ 63.1567(a)(3)]
d. Recordkeeping and reporting requirements. [§ 63.1567(a)(3)]

EUG 17: Coker Enclosed Blowdown

a. All non-condensable vapors from the Enclosed Coker Blowdown system shall be ducted to a flare. The Coker Enclosed Blowdown Vent is regulated under EUG 14.

EUG 18: EUG 18: 63.640 (Subpart CC), Existing Group 1 Internal Floating Roof Storage Vessels constructed prior to 6/12/73

Tank #	EU	Point ID
13	6333	Tk13
21	6336	Tk21
22	6337	Tk22
31	6340	Tk31
153	6346	Tk153
186	6348	Tk186
187	6349	Tk187
188	13592	Tk188

Tank #	EU	Point ID
242	6359	Tk242
244	6360	Tk244
473	6387	Tk473
474	6388	Tk474
411	13579	Tk411
413	6341	Tk413
502	1359	Tk502
742	6392	Tk742

a. Each of the above storage tanks shall be equipped with an internal floating roof. [40 CFR 63.119]
b. Each tank shall comply with the floating roof requirements listed in 40 CFR 63.119(b)
c. The permittee shall comply with the compliance provisions found in 40 CFR 63.120(a).
d. The permittee shall follow the reporting requirements found in 40 CFR 63.122(a) and (c).
e. The permittee shall maintain records as required in 40 CFR 63.123(a).

EUG 19: 63.640 (Subpart CC) Existing Group 1 External Floating Roof Storage Vessels. External Floating Roof Tanks emptied and degassed since 8/18/98, 63.640(h)(4).

Tank #	EU	Point ID
199	6353	Tk199
307	6367	Tk307
750	6396	Tk750
752	6398	Tk752
755	6399	Tk755
779	6401	Tk779
874	6405	Tk874

a. The tanks are subject to 40 CFR 63 Subpart CC (§63.640 *et seq*), to OAC 252:100-37-15(a) and (b) and to OAC 252:100-39-41(a), (b), and (e)(1). Subpart CC references provisions of MACT G (SOCMI) found at 40 CFR 63.110 *et seq.* Many of the requirements overlap, so conditions represent the most stringent version of each.
b. The tanks may not store VOCs that have a true vapor pressure that exceeds 11.1 psia. [§63.119(a)(1)]
c. The accumulated areas of gaps between the vessel wall and the primary seal shall not exceed 10 square inches per foot of vessel diameter, and the width of any portion of any gap shall not exceed 1.5 inches. [§63.120(b)(3)]
d. The accumulated area of gaps between the vessel wall and the secondary seal, as determined below, shall not exceed 1.0 square inch per foot of vessel diameter and the width of any portion of any gap shall not exceed 0.5 inches. These seal gap requirements may be exceeded during the measurement of primary seal gaps as required by § 63.646 per 63.119(c)(1)(iii). [§63.120(b)(4)]

e. The operator of a Group 1 storage vessel subject to this 40 CFR 63, Subpart CC shall comply with the applicable requirements of §§63.119 through 63.121 except as provided in paragraphs (b) through (l) of §646. [§63.646]

f. When the operator and the DEQ do not agree on whether the annual weight percent organic HAP in the stored liquid is above or below four (4) percent for a storage vessel, EPA Method 18, of 40 CFR 60, Appendix A shall be used. [§63.646(b)(2)]

g. Except as provided below, the operator shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage vessel, and the secondary seal and the wall of the storage vessel according to the following frequency. [§63.120(b)(1)]
   1. Measurements of gaps between the vessel wall and the primary seal shall be performed at least once every five (5) years. [§63.120(b)(1)(i)]
   2. Measurements of gaps between the vessel wall and the secondary seal shall be performed at least once per year. [§63.120(b)(1)(iii)]
   3. If any storage vessel ceases to store organic HAP for a period of one (1) year or more, or if the maximum true vapor pressure of the total organic HAPs in the stored liquid falls below the value defining Group 1 storage vessels for a period of one (1) year or more, measurements of gaps between the vessel wall and the primary seal, and the gaps between the vessel wall and the secondary seal shall be performed within ninety (90) calendar days of the vessel being refilled with organic HAP. [§63.120(b)(1)(iv)]

h. The operator shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by complying with applicable requirements in § 63.120 (b) [§63.120(b)(2)]
   1. If the operator utilizes the extension specified for this source, the operator shall document the decision. Documentation of a decision to utilize the extension shall include: a description of the failure, document that alternate storage capacity is unavailable, and specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied, as soon as practical. [§63.120(b)(8)]
   2. Except as below, for all the inspections required, the operator shall notify the DEQ in writing at least thirty (30) calendar days prior to the refilling of each storage vessel with organic HAP to afford the DEQ the opportunity to inspect the storage vessel prior to refilling. [§63.120(b)(9)]
   3. If the inspection required is not planned and the operator could not have known about the inspection thirty (30) calendar days in advance of refilling the vessel with organic HAP, the operator shall notify the DEQ at least seven (7) calendar days prior to refilling of a storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternately, the notification including the written documentation may be made in writing and sent so that it is received by the DEQ at least seven (7) calendar days prior to refilling. [§63.120(b)(10)(iii)]
   4. The DEQ can waive the notification requirements specified for all or some storage vessels subject to these requirements. The Department may also grant permission to refill storage vessels sooner than thirty (30) days after submitting the notifications specified or sooner than 7 days after submitting the notification required for all storage vessels at a refinery or for individual storage vessels on a case-by case basis. [§63.646(l)]

5. The operator shall notify the DEQ in writing thirty (30) calendar days in advance of any gap measurements required to afford the DEQ the opportunity to have an observer present. [§63.120(b)(9)]
6. If noncompliant seal gaps are found during the required inspections or if the specification are not met, the operator shall report the following information in the Periodic Report: [§63.122(e)(1)]
   A) Date of the seal gap measurement.
   B) The raw data obtained in the seal gap measurement and the calculations described.
   C) Description of any seal condition that is not met.
   D) Description of the nature of and date the repair was made, or the date the storage vessel was emptied.
7. If a failure is detected during the inspection (i.e., internal inspection), the operator shall report the following information in the Periodic Report. A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric. [§63.122(e)(3)(ii)]
   A) Date of the inspection.
   B) Identification of each storage vessel in which a failure was detected.
   C) Description of the failure.
   D) Describe the nature of and date the repair was made.
8. If an extension is utilized, the operator shall, in the next Periodic Report include the following. [§63.120(b)(8)]
   A) Identify the storage vessel.
   B) Description of the failure.
   C) Document that alternate storage capacity was not available.
   D) Describe the nature of and date the repair was made.
9. The external floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the following periods. [§63.119(c)(3)]
   A) During the initial fill.
   B) After the vessel has been completely emptied and degassed.
   C) When the vessel is completely emptied before being subsequently refilled.
10. When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical. [§63.119(c)(4)]

    Note: The intent is to avoid having a vapor space between the floating roof and the stored liquid for extended periods. Storage vessels may be emptied for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations. Storage vessels where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity are considered completely empty.
11. Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device meets the following criteria. [§63.119(c)(1)]
    A) §63.119(c)(1)(i) Consist of two seals, one above the other.

B) §63.119(c)(1)(ii) The primary seal shall be either a metallic shoe seal or a liquid-mounted seal.

12. Except during inspections required, both the primary and secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion. [§63.119(c)(1)(iii)]
13. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. [§63.119(c)(2)(iii)]

14. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access. [§63.119(c)(2)(ii)]
15. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting. [§63.119(c)(2)(iv)]
16. The primary seal shall also meet the following requirements: [§63.120(b)(3)]
    a. Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 24 inches above the stored liquid surface.
    b. There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope. [§63.120(b)(6)]
    c. The secondary seal shall also meet the following requirements:
        i. The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as allowed.
        ii. There shall be no holes, tears, or other openings in the seal or seal fabric.
    d. If during the inspections required, the primary seal has holes, tears or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings, the operator shall repair the items as necessary so that none of the conditions specified in this subcondition exist before refilling the storage vessel with organic HAP. [§63.120(b)(10)(i)]

    e. The operator shall repair any conditions that do not meet the requirements, above, no later than forty-five (45) calendar days after identification, or shall empty and remove the storage vessel from service no later than forty-five (45) calendar days after identification. If, during such seal gap measurements or such inspections, a failure is detected that cannot be repaired within forty-five (45) calendar days and if the vessel cannot be emptied within forty-five (45) calendar days, the operator may utilize up to 2 extensions of up to thirty (30) additional calendar days each. The decision to utilize an extension must be documented. [§63.120(b)(8)]
    f. The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche. [§63.642(e)]

EUG 20: 63.640 (Subpart CC) Group 2 Storage Vessels. All tanks constructed before 1970.

Tank #	EU	Point ID
6	20128	Tk6
30	13559	Tk30
41	1356	Tk41
155	13563	Tk155
181	20129	Tk181
189	6350	Tk189
190	6351	Tk190
277	13573	Tk277

Tank #	EU	Point ID
279	6364	Tk279
281	13574	Tk281
283	13576	Tk283
315	6370	Tk315
401	6375	Tk401
696	NA	Tk696
747	6393	Tk747
751	5397	Tk751

a. The tanks shall not store liquids with a stored-liquid maximum true vapor pressure greater than or equal to 1.5 psia and stored-liquid annual average true vapor pressure greater than or equal to 1.2 psia and annual average HAP liquid concentration greater than four (4) percent by weight total organic HAP. [§63.641]

b. When the operator and the DEQ do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below four (4) percent for a storage vessel, EPA Method 18, of 40 CFR 60, Appendix A, shall be used. [§63.646(b)(2)]

c. If a storage vessel is determined to be a Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent, a record of any data, assumptions, and procedures used to make this determination shall be retained. [§63.654(i)(iv)]

d. The operator shall keep readily accessible records showing the dimensions of the storage vessel and an analysis showing the capacity of the storage vessel. This record shall be kept as long as the storage vessel retains Group 2 status and is in operation. [§63.123(a)]

e. If a deliberate operational process change is made to an existing petroleum refining process unit and the change causes a Group 2 emission point to become a Group 1 emission point, as defined in §63.641, then the owner or operator shall comply with the requirements for existing sources for the Group 1 emission point upon initial start-up, unless the owner or operator demonstrates to DEQ that achieving compliance will take longer than making the change. If this demonstration is made to DEQ's satisfaction, the owner or operator shall follow the procedures in Condition #05(2)(A) through (C) to establish a compliance date. [§63.640(l)(ii)]

f. If a change that does not meet the criteria above is made to a petroleum refining process unit and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), then the owner or operator shall comply with the requirements for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1. The owner or operator shall submit a compliance schedule to the DEQ for approval, along with a justification for the schedule. [§63.640(m)]

g. The compliance schedule shall be submitted within 180 days after the change is made, unless the compliance schedule has been previously submitted to the permitting authority. If it is not possible to determine until after the change is implemented whether the emission point has become Group 1, the compliance schedule shall be submitted within

180 days of the date when the effect of the change is known to the source. The compliance schedule may be submitted in the next Periodic Report if the change is made after the date the Notification of Compliance Status report is due.

h. The DEQ shall approve or deny the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification. Approval is automatic if not received from the DEQ within 120 calendar days of receipt.
i. If a performance test for determination of compliance for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic report, the results of the performance test shall be included in the Periodic Report. [§63.654(g)(7)]
j. The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche. Records and reports of start-up, shutdown and malfunction are not required if they pertain solely to Group 2 emission points that are not included in an emission average. [§63.642(e) and §63.654(h)(1)]

EUG 21: NSPS 60.110b (Subpart Kb) Internal Floating Roof Storage Vessels Storing Volatile Organic Liquids Above 0.75 psia Vapor Pressure, Group 2.

Tank #	EU	Point ID
25	6338	Tk25
1061	13594	Tk1061
1070	20126	Tk1070
1080	NA	Tk1080
782	6402	Tk782

a. The tanks are subject to 40 CFR 60 Subpart Kb (§60.110b *et seq*) and to OAC 252:100-39-41(a), (b), and (e)(1). Conditions represent the most stringent provisions of each.
b. The tanks may not store VOCs that have a true vapor pressure that exceeds 11.1 psia. [§60.112b(a)]
c. The accumulated areas of gaps between the vessel wall and the primary seal shall not exceed 10 square inches per foot of vessel diameter, and the width of any portion of any gap shall not exceed 1.5 inches. [§60.113b(b)(4)(i)]
d. The accumulated area of gaps between the vessel wall and the secondary seal shall not exceed 1.0 square inch per foot of vessel diameter and the width of any portion of any gap shall not exceed 0.5 inches. These seal gap requirements may be exceeded during the measurement of primary seal gaps. [§60.113b(b)(4)(ii)(B)]
e. Available data on the storage temperature may be used to determine the maximum true vapor pressure based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service. [§60.116b(e)(1)]
f. For crude oil or refined petroleum products the vapor pressure may be obtained by using the available data on the Reid vapor pressure and the maximum expected storage

temperature based on the highest expected calendar-month average temperature of the stored product to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference – see §60.17), unless the DEQ specifically requests that the liquid be sampled, the actual storage temperature determined and the Reid vapor pressure determined from the sample(s). [§60.116b(e)(2)]

g. The operator shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage vessel, and the secondary seal and the wall of the storage vessel according to the following frequency. [§60.113b(b)(1)]
    1. Measurements of gaps between the vessel wall and the primary seal shall be performed at least once every five (5) years. [§60.113b(b)(1)(i)]
    2. Measurements of gaps between the vessel wall and the secondary seal shall be performed at least once per year. [§60.113b(b)(1)(ii)]
    3. If any storage vessel ceases to store VOL for a period of one (1) year or more, measurements of gaps between the vessel wall and the primary seal, and the gaps between the vessel wall and the secondary seal shall be performed within sixty (60) calendar days of the vessel being refilled with VOL. [§60.113b(b)(1)(iii)]

h. The operator shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described in §60.113b(b)(2).

i. The operator shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed. [§60.113b(b)(6)]

j. Within 60 days of performing the seal gap measurements required, the operator shall furnish DEQ with a report that contains: [§60.113b(b)(2)]
    1. the date of the measurement;
    2. the raw data obtained in the measurement; and
    3. the calculations of seal gap area.

k. The owner shall keep a record of each gap measurement performed as required. Each record shall identify the storage vessel in which the measurement was performed and shall contain the data above. These records shall be maintained for a period of two years from date of recording. [§60.113b(b)(3)]

l. As specified in 40 CFR 60.7(f), any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and all other information required by this part recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance and records.
    1. The permittee shall keep readily accessible records showing the dimensions of the storage vessels and an analysis showing the capacity of the vessels. This record shall be kept for the life of the source. [§60.116b(b)]
    2. The permittee shall maintain a record for Tank No. 583 of the cumulative annual throughput, the volatile organic liquid stored, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period.
    3. Copies of these records shall be retained on location for at least two years after the dates of recording.
    4. The permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the air pollution control equipment on these vessels. These records shall be retained in a file for at least two years after the dates of recording. [§60.7(b)]

m. If the operator utilizes the extension specified, of this source, the operator shall document the decision. Documentation of a decision to utilize the extension shall include: a description of the failure, document that alternate storage capacity is unavailable, and specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied, as soon as practical. [§60.113b(b)(4)(iii)]

n. The operator shall keep a record of each inspection performed as required. Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component or the control equipment.

o. Except as provided below, for all the inspections required, the operator shall notify the DEQ in writing at least thirty (30) calendar days prior to the refilling of each storage vessel with VOL to afford the DEQ the opportunity to inspect the storage vessel prior to refilling. [§60.113b(b)(6)(ii)]

   1. If the inspection required above, is not planned and the operator could not have known about the inspection thirty (30) calendar days in advance of refilling the vessel with organic HAP, the operator shall notify the DEQ at least seven (7) calendar days prior to refilling of a storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternately, the notification including the written documentation may be made in writing and sent so that it is received by the DEQ at least seven (7) calendar days prior to refilling. [§60.113b(b)(6)(ii)]
   2. The operator shall notify the DEQ in writing thirty (30) calendar days in advance of any gap measurements required, to afford the DEQ the opportunity to have an observer present. [§60.113b(b)(5)]
   3. If noncompliant seal gaps are found during the required inspections or if the specification are not met, the operator shall report the following information to the DEQ within 30 days of the inspection. [§60.115b(b)(4)]
      A) Date of the seal gap measurement.
      B) The raw data obtained in the seal gap measurement and the calculations described.
      C) Description of the nature of and date the repair was made, or the date the storage vessel was emptied.

p. The external floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the following periods. [§60.112b(a)(2)(iii)]

   1. During the initial fill.
   2. When the vessel is completely emptied before being subsequently refilled.

q. When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible. [§60.112b(a)(2)(iii)]

r. Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device must meet the following criteria. [§60.112b(a)(2)(i)]

   1. Consist of two seals, one above the other. [§60.112b(a)(2)(i)]
   2. The primary seal shall be either a metallic shoe seal or a liquid-mounted seal. [§60.112b(a)(2)(i)(A)]

s. Except as allowed, both the primary and secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion. [§60.112b(a)(2)(i)]

t. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. [§60.112b(a)(2)(ii)]

u. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except with the device is in actual use. [§60.112b(a)(2)(ii)]

v. Rim vents are to be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. [§60.112b(a)(2)(ii)]

w. The primary seal shall also meet the following requirements.
    1. Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 24 inches above the stored liquid surface. [§60.113b(b)(4)(i)(A)]
    2. There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope. [§60.113b(b)(4)(i)(B)]

x. The secondary seal shall also meet the following requirements. [§60.113b(b)(4)(ii)]
    1. The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as provided. [§60.113b(b)(4)(ii)(A)]
    2. There shall be no holes, tears, or other openings in the seal or seal fabric. [§60.113b(b)(4)(ii)(C)]

y. If during the inspections required, the primary seal has holes, tears or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings, the operator shall repair the items as necessary so that none of the conditions specified in this subcondition exist before refilling the storage vessel with VOL. [§60.113b(b)(6)(i)]

z. The operator shall repair any conditions that do not meet the requirements, no later than forty-five (45) calendar days after identification, or shall empty the storage vessel. If a failure is detected that cannot be repaired within forty-five (45) calendar days and if the vessel cannot be emptied within forty-five (45) calendar days, a 30-day extension may be requested from DEQ in the inspection report required. Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [§60.113b(b)(4)(iii)]

EUG 22: NSPS 60.110b (Subpart Kb) External Floating Roof Storage Vessel Storing VOL Above 0.75 psia Vapor Pressure.

Tank #	EU	Point ID
583	13591	Tk583

a. The tank is subject to 40 CFR 60 Subpart Kb (§60.110b *et seq*) and to OAC 252:100-39-41(a), (b), and (e)(1). Conditions represent the most stringent provisions of each.

b. The tank may not store VOCs that have a true vapor pressure that exceeds 11.1 psia. [§60.112b(a)]

c. The accumulated areas of gaps between the vessel wall and the primary seal shall not exceed 10 square inches per foot of vessel diameter, and the width of any portion of any gap shall not exceed 1.5 inches. [§60.113b(b)(4)(i)]

d. The accumulated area of gaps between the vessel wall and the secondary seal shall not exceed 1.0 square inch per foot of vessel diameter and the width of any portion of any gap shall not exceed 0.5 inches. These seal gap requirements may be exceeded during the measurement of primary seal gaps. [§60.113b(b)(4)(ii)(B)]

e. Available data on the storage temperature may be used to determine the maximum true vapor pressure based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service. [§60.116b(e)(1)]

f. For crude oil or refined petroleum products the vapor pressure may be obtained by using the available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference – see §60.17), unless the DEQ specifically requests that the liquid be sampled, the actual storage temperature determined and the Reid vapor pressure determined from the sample(s). [§60.116b(e)(2)]

   1. The operator shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage vessel, and the secondary seal and the wall of the storage vessel according to the following frequency. [§60.113b(b)(1)]
   2. Measurements of gaps between the vessel wall and the primary seal shall be performed at least once every five (5) years.
   3. §60.113b(b)(1)(ii) Measurements of gaps between the vessel wall and the secondary seal shall be performed at least once per year.

g. If any storage vessel ceases to store VOL for a period of one (1) year or more, measurements of gaps between the vessel wall and the primary seal, and the gaps between the vessel wall and the secondary seal shall be performed within sixty (60) calendar days of the vessel being refilled with VOL. [§60.113b(b)(1)(iii)]

h. The operator shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described below. [§60.113b(b)(2)]

1. Seal gaps, if any, shall be measured at one or more floating roof levels when the roof is not resting on the roof leg supports. [§60.113b(b)(2)(i)]
2. Seal gaps, if any, shall be measured around the entire circumference of the vessel in each place where a one-eighth (1/8) inch diameter uniform probe passes freely (without forcing or binding against the seal) between the seal and the wall of the storage vessel. The circumferential distance of each such location shall also be measured. [§60.113b(b)(2)(ii)]
3. The total surface area of each gap described in subcondition (2)(B), above, shall be determined by using probes of various widths to measure accurately the actual distance from the vessel wall to the seal and multiplying each such width by its respective circumferential distance. [§60.113b(b)(2)(iii)]
4. The operator shall add the gap surface area of each gap location for the primary seal and divide the sum by the nominal diameter of the vessel. [§60.113b(b)(3)]
5. The operator shall add the gap surface area of each gap location for the secondary seal and divide the sum by the nominal diameter of the vessel. [§60.113b(b)(3)]
    a. The operator shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed. [§60.113b(b)(6)]

i. Within 60 days of performing the seal gap measurements required, the operator shall furnish DEQ with a report that contains: [§60.113b(b)(2)]
   1. the date of the measurement;
   2. the raw data obtained in the measurement; and
   3. the calculations of seal gap areas.

j. The owner shall keep a record of each gap measurement performed as required. Each record shall identify the storage vessel in which the measurement was performed and shall contain the data above. These records shall be maintained for a period of two years from date of recording. [§60.113b(b)(3)]

k. As specified in 40 CFR 60.7(f), any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and all other information required by this part recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance and records. [§60.7(f)]

l. The permittee shall keep readily accessible records showing the dimensions of the storage vessels and an analysis showing the capacity of the vessels. This record shall be kept for the life of the source. [§60.116b(b)]

m. The permittee shall maintain a record for the tank of the cumulative annual throughput, the volatile organic liquid stored, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period. Copies of these records shall be retained on location for at least two years after the dates of recording.

n. The permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the air pollution control equipment on these vessels. These records shall be retained in a file for at least two years after the dates of recording. [§60.7(b)]

o. If the operator utilizes the extension specified, the operator shall document the decision. Documentation of a decision to utilize the extension shall include: a description of the failure, document that alternate storage capacity is unavailable, and specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied, as soon as practical. [§60.113b(b)(4)(iii)]

p. The operator shall keep a record of each inspection performed as required. Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component or the control equipment.

q. Except as provided below, for all the inspections required, the operator shall notify the DEQ in writing at least thirty (30) calendar days prior to the refilling of each storage vessel with VOL to afford the DEQ the opportunity to inspect the storage vessel prior to refilling. [§60.113b(b)(6)(ii)]

r. If the inspection required above is not planned and the operator could not have known about the inspection thirty (30) calendar days in advance of refilling the vessel with organic HAP, the operator shall notify the DEQ at least seven (7) calendar days prior to refilling of a storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternately, the notification including the written documentation may be made in writing and sent so that it is received by the DEQ at least seven (7) calendar days prior to refilling. [§60.113b(b)(6)(ii)]

s. The operator shall notify the DEQ in writing thirty (30) calendar days in advance of any gap measurements to afford the DEQ the opportunity to have an observer present. [§60.113b(b)(5)]

t. If seal gaps in exceedance of limitations above are found during the inspections required or if the specification are not met, the operator shall report the following information to the DEQ within 30 days of the inspection. [§60.115b(b)(4)]
   1. Date of the seal gap measurement.
   2. The raw data obtained in the seal gap measurement and the calculations.
   3. Description of the nature of and date the repair was made, or the date the storage vessel was emptied.

u. The external floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the following periods. [§60.112b(a)(2)(iii)]
   1. During the initial fill.
   2. When the vessel is completely emptied before being subsequently refilled.

v. When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible. [§60.112b(a)(2)(iii)]

w. Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device must meet the following criteria. [§60.112b(a)(2)(i)]
   1. Consist of two seals, one above the other. [§60.112b(a)(2)(i)]
   2. The primary seal shall be either a metallic shoe seal or a liquid-mounted seal. [§60.112b(a)(2)(i)(A)]

x. Except as allowed, both the primary and secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion. [§60.112b(a)(2)(i)]

y. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. [§60.112b(a)(2)(ii)]

z. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except with the device is in actual use. [§60.112b(a)(2)(ii)]

aa. Rim vents are to be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. [§60.112b(a)(2)(ii)]

bb. The primary seal shall also meet the following requirements.
  1. Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 24 inches above the stored liquid surface. [§60.113b(b)(4)(i)(A)]
  2. There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope. [§60.113b(b)(4)(i)(B)]

cc. The secondary seal shall also meet the following requirements. [§60.113b(b)(4)(ii)]
  1. The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as provided. [§60.113b(b)(4)(ii)(A)]
  2. There shall be no holes, tears, or other openings in the seal or seal fabric. [§60.113b(b)(4)(ii)(C)]

dd. If during the inspections required, the primary seal has holes, tears or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings, the operator shall repair the items as necessary so that none of the conditions specified in this subcondition exist before refilling the storage vessel with VOL. [§60.113b(b)(6)(i)]

ee. The operator shall repair any conditions that do not meet the requirements above, no later than forty-five (45) calendar days after identification, or shall empty the storage vessel. If a failure is detected that cannot be repaired within forty-five (45) calendar days and if the vessel cannot be emptied within forty-five (45) calendar days, a 30-day extension may be requested from DEQ in the inspection report required. Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [§60.113b(b)(4)(iii)]

EUG 23: NSPS 60.110b Subpart Kb tanks Storing Volatile Organic Liquids (VOL) Below 0.507 psia Vapor Pressure.

CD	Tank #	EU	Point ID
2010	27	13588	Tk27
1917	84	NA	Tk84
1917	85	NA	Tk85
2012	189	6350	Tk189
2009	405	6377	Tk405
2009	406	13578	Tk406
1985	997	13588	Tk997
1985	998	13589	Tk998
1987	1002	6406	Tk1002
1989	1005	NA	Tk1005
1990	1012	15950	Tk1012
2012	1038	1038	Tk1038
1993	1039	16561	Tk1039
2013	157	14307	Tk157

a. The operator shall not store VOL with a true vapor pressure that exceeds or equals 0.507 psia. [60.110b(b)]
b. Tanks 84 and 85 were rehabilitated and modified under construction Permit No. 99-355-C, issued March 24, 2000. The permit authorized VOC emissions of 0.037 TPY for each tank and limited throughput to 3.02 million gallons per year for each tank.
c. The owner or operator shall keep copies of all records required by this section for at least 5 years, except for the record required by 60.116b(b), concerning dimensions of the storage vessels and an analysis showing the capacity of the vessels. This record shall be kept for the life of the tanks. [60.116b(a)]
d. A copy of these records shall be retained on-site or at a local field office for at least five years after the dates of recording. The following records shall be made available to regulatory personnel upon request.
    1. Volatile organic liquid stored in the tanks, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period.
    2. Total throughput of wax (monthly and cumulative annual).
    3. Test results of any leak detection and repair program carried out.

EUG 24: NSPS 60.110a Storage Vessels Storing Petroleum Liquids Below 1.0 psia Vapor Pressure

CD	Tank #	EU	Point ID
1980	224	13569	Tk224
1988	277	13573	Tk277
1979	881	NA	Tk881
1983	890	NA	Tk890
1982	992	NA	Tk992
1982	993	NA	Tk993

a. Storage vessels that are of the capacity identified in §60.110a(a) and that are constructed after May 18, 1978, and before July 23, 1984, and storing petroleum liquids with true vapor pressure (TVP) less than 1.5 psia are exempt from the standards of §60.112a, from the testing and procedures of §60.113a, and from the alternative limitations of §60.114a. Further, vessels storing liquids with TVP less than 1.0 psia are exempt from the monitoring requirements of §60.115a. Thus, the only requirement for this EUG is that the operator shall not store petroleum liquids with a true vapor pressure that exceeds 1.0 psia.

EUG 25: NSPS 60.110 (Subpart K) Storage Vessels Storing Petroleum Liquids Below 6.9 kPa Reid Vapor Pressure (1.0 psia)

CD	Tank #	EU	Point ID
1974	152	6324	Tk152
1973	158	13565	Tk158
1977	468	NA	Tk468
1978	472	NA	Tk472
1976	983	NA	Tk983
1976	984	NA	Tk984
1976	986	NA	Tk986
1976	987	NA	Tk987

a. Storage vessels that are of the capacity identified in §60.110 and that are constructed after June 11, 1973, and before May 19, 1978, and storing petroleum liquids with true vapor pressure (TVP) less than 1.5 psia are exempt from the VOC standards of §60.112. Further, vessels storing liquids with TVP less than 1.0 psia are exempt from the monitoring requirements of §60.113. Thus, the only requirement for this EUG is that the operator shall not store petroleum liquids with a true vapor pressure that exceeds 1.0 psia.

EUG 27: External Floating Roof Storage Vessels Subject to OAC 252:100-39-41. (previously listed in group 2 tanks)

CD	Tank #	EU	Point ID
1957	314	6369	Tk314

a. The operator shall not store VOCs that have a vapor pressure of 11.1 psia or greater under actual storage conditions.

[OAC 252:100-37-15(a)(1) and OAC 252:100-39-41(a)(1)]

b. Although OAC:100-39-41 and 100-37 do not specify inspection frequency or recordkeeping requirements, inspections shall be performed annually.

c. Each VOC storage vessel with a capacity of 400 gal (1.5 m^3) or more shall be equipped with a permanent submerged fill pipe.

[OAC 252:100-37-15(b) and OAC 252:100-39-41(b)]

EUG 28: Cone Roof Tanks

All of these tanks were constructed before the applicability date of any rules and contain liquids with vapor pressure below any of the thresholds necessary to make the tanks subject to any state rules affecting "existing" tanks.

EU	Point ID	EU	Point ID	EU	Point ID
20127	Tk1	6344	Tk151	Tk318	Tk318
Tk9	Tk9	13564	Tk156	Tk319	Tk319
Tk10	Tk10	15944	Tk159	Tk320	Tk320
Tk11	Tk11	Tk192	Tk192	Tk321	Tk321
6334	Tk15	15945	Tk193	Tk322	Tk322
6335	Tk16	13567	Tk194	6371	Tk323
Tk23	Tk23	Tk195	Tk195	Tk327	Tk327
Tk26	Tk26	Tk196	Tk196	Tk328	Tk328
20130	Tk28	6355	Tk215	Tk329	Tk329
6339	Tk29	15946	Tk217	Tk331	Tk331
Tk33	Tk33	13568	Tk218	Tk332	Tk332
Tk34	Tk34	Tk223	Tk223	Tk335	Tk335
6342	Tk35	Tk227	Tk227	Tk390	Tk390
6343	Tk36	Tk228	Tk228	Tk391	Tk391
Tk38	Tk38	Tk229	Tk229	Tk392	Tk392
Tk45	Tk45	Tk232	Tk232	Tk393	Tk393
Tk46	Tk46	Tk233	Tk233	Tk394	Tk394
Tk52	Tk52	Tk234	Tk234	Tk396	Tk396
Tk53	Tk53	Tk235	Tk235	Tk397	Tk397
Tk54	Tk54	Tk236	Tk236	6373	Tk398
Tk62	Tk62	Tk237	Tk237	6374	Tk399
Tk65	Tk65	Tk240	Tk240	Tk471	Tk471
Tk66	Tk66	Tk252	Tk252	Tk509	Tk509
Tk68	Tk68	Tk264	Tk264	6389	Tk510
Tk69	Tk69	Tk265	Tk265	6390	Tk511
Tk71	Tk71	Tk266	Tk266	6391	Tk519
Tk72	Tk72	Tk267	Tk267	Tk645	Tk645
Tk73	Tk73	Tk271	Tk271	Tk646	Tk646
Tk74	Tk74	6363	Tk272	Tk649	Tk649
Tk75	Tk75	Tk273	Tk273	Tk650	Tk650
Tk76	Tk76	Tk274	Tk274	Tk675	Tk675
Tk79	Tk79	Tk275	Tk275	Tk691	Tk691
Tk80	Tk80	Tk276	Tk276	Tk692	Tk692
Tk81	Tk81	6364	Tk279	Tk693	Tk693
Tk83	Tk83	6356	Tk280	Tk694	Tk694
Tk132	Tk132	6366	Tk284	Tk700	Tk700
Tk133	Tk133	Tk305	Tk305	13585	Tk701
Tk134	Tk134	Tk317	Tk317	13584	Tk702

EU	Point ID
6403	Tk799
Tk800	Tk800
15958	Tk801
13586	Tk802
15949	Tk803
Tk807	Tk807
Tk828	Tk828
Tk829	Tk829
Tk830	Tk830
Tk831	Tk831
Tk851	Tk851
Tk852	Tk852
Tk853	Tk853
Tk854	Tk854
Tk855	Tk855
Tk856	Tk856
Tk857	Tk857
Tk861	Tk861
Tk865	Tk865
Tk867	Tk867
13587	Tk870
Tk875	Tk875
Tk876	Tk876
Tk877	Tk877
Tk878	Tk878
Tk879	Tk879
Tk880	Tk880
Tk882	Tk882
Tk883	Tk883
Tk884	Tk884
Tk885	Tk885
Tk886	Tk886
Tk887	Tk887
Tk888	Tk888
Tk891	Tk891
Tk893	Tk893
Tk898	Tk898
Tk913	Tk913
Tk914	Tk914
Tk916	Tk916
Tk918	Tk918
Tk921	Tk921
Tk922	Tk922

EU	Point ID
Tk923	Tk923
Tk924	Tk924
Tk925	Tk925
Tk926	Tk926
Tk927	Tk927
Tk928	Tk928
Tk929	Tk929
Tk835	Tk835
6404	Tk838
Tk847	Tk847
Tk848	Tk848
Tk930	Tk930
Tk931	Tk931
Tk932	Tk932
Tk933	Tk933
Tk934	Tk934
Tk935	Tk935
Tk936	Tk936
Tk937	Tk937
Tk938	Tk938
Tk939	Tk939
Tk940	Tk940
Tk941	Tk941
Tk942	Tk942
Tk943	Tk943
Tk944	Tk944
Tk955	Tk955
TkAGT1	TkAGT1
TkAGT2	TkAGT2
TkAGT3	TkAGT3
TkAGT4	TkAGT4

a. Records sufficient to demonstrate that these tanks contain liquids with vapor pressure below any applicable standard shall be maintained. Such records shall be sufficient to demonstrate that each tank remains a Group 2 tank under 40 CFR 63 Subpart CC.

EUG 29: Pressurized Spheres containing VOC with vapor pressure > 11.1 psia

Tank #	EU	Point ID
Tk 585	NA	Tk585
Tk 586	NA	Tk586
Tk 587	NA	Tk587
Tk 588	NA	Tk588
Tk 589	NA	Tk589
Tk 788	NA	Tk788
Tk 789	NA	Tk789
Tk 797	NA	Tk797
Tk 798	NA	Tk798
Tk 804	NA	Tk804
Tk 805	NA	Tk805
Tk 806	NA	Tk806

a. No limits apply to these vessels. These vessels predate most federal and state rules and regulations. Since they are pressurized, they satisfy the requirements of OAC 252:100-39-41. Pressurized vessels do not meet the definition of storage vessels in MACT CC, per 40 CFR 63.641.

EUG 30: Pressurized Bullet Tanks containing VOC with vapor pressure > 11.1 psia

Tank #	EU	Point ID
Tk 1007	NA	Tk1007
Tk 1008	NA	Tk1008
Tk 791	NA	Tk 791
Tk 792	NA	Tk 792
Tk 793	NA	Tk 793
Tk 794	NA	Tk 794
Tk 795	NA	Tk 795

a. No limits apply to the vessels. These vessels predate most federal and state rules and regulations. Since they are pressurized, they satisfy the requirements of OAC 252:100-39-41. Pressurized vessels do not meet the definition of storage vessels in MACT CC, per 40 CFR 63.641.

EUG 31: Underground LPG Cavern (pseudo pressure vessel)

CD	Tank #	EU	Point ID
1961	Tk 900	NA	Tk900

a. No limits apply to this cavern. This "vessel" predates federal and state rules and regulations. Since it is pressurized, it satisfies the requirements of OAC 252:100-39-41. Pressurized vessels do not meet the definition of storage vessels in MACT CC, per 40 CFR 63.641.

EUG 32: Non-gasoline Loading Racks

EU	Equipment Point ID	Installed Date
NA	Black Oil Loading Rack	1937
NA	Extract Truck Loading Rack	1993
NA	Extract Rail Loading Rack	1930
NA	Wax Truck Loading Rack	1979
NA	Wax Rail Loading Rack	1917
NA	LOB Rail Loading Rack	1967
NA	LOB Truck Loading Rack	1978
NA	Resid Truck Loading Rack	1962
NA	Diesel Rail Loading Rack	1986
NA	Coke Truck Loading Area	1991

a. No limits apply to the loading racks.

EUG 33: LPG Loading Racks

EU	Equipment Point ID	Installed Date
NA	LPG Rail Loading Rack	1917
NA	LPG Truck Loading Rack	1956

a. When loading is by means other than hatches, all loading and vapor lines shall be equipped with fittings that make vapor-tight connections and which close automatically when disconnected per OAC 252:100-39-41(c)(4).
b. In addition to those requirements contained in 252:100-39-41(c), stationary loading facilities shall be checked annually in accordance with EPA Test Method 21, Leak Test. Leaks greater than 5,000 ppmv shall be repaired within 15 days. Facilities shall retain inspection and repair records for at least two years.

EUG 34: Cooling Towers

EU	Point ID	Equipment
15942	CT2	LEU/MEK Cooling Tower
15942	CT3	Coker/#2 Platformer Cooling Tower
15942	CT4	LEU/MEK Cooling Tower
15942	CT6	PDA/#5 BH Cooling Tower
15942	CT8	CDU Cooling Tower
15942	CT9	BSU Cooling Tower
15942	CT3A	Plat Cooling Tower
15942	CT3B	Coker Cooling Tower

a. Cooling towers are subject to 40 CFR Part 63 Subpart CC, and shall comply with applicable standards for "heat exchange systems." [40 CFR 63.654]

EUG 35: Oil/Water Separators Subject to OAC 252:100-37-37 and 39-18

EU	Point ID	Equipment	Installed Date
NA	D-40	Separator at Lube Packaging	Before 7/1/72
NA	D-41	Separator at Lube Blending and Tankage	Before 7/1/72
NA	D-42	Separator from MEK/Lube Unit	Before 7/1/72
NA	S1-51	Separator at Belt Press (sealed)	1985
6332	Tk 532	Separator at T&S (sealed)	Before 7/1/72
6331	Tk 533	Separator at T&S (sealed)	Before 7/1/72

a. A single-compartment or multiple-compartment VOC/water separator that receives effluent water containing 200 gals/d (760 l/d) or more of any VOC from any equipment processing, refining, treating, storing or handling VOCs shall be equipped such that the container totally encloses the liquid contents and all openings are sealed. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair is in progress. [OAC 252:100-37-37 (1) and OAC 252:100-39-18(b)(1)]

EUG 36: Spark Ignition Internal Combustion Engines Subject to 40 CFR Part 63 Subpart ZZZZ

EU #	Equipment Point ID	HP	Equip #	Make	Installed Date
257	#3 CT Circulation Pump	650	EG-5156	Waukesha	
256	#6 CT Circulation Pump	615	EG-5152	Caterpillar	
	Emergency	45	EG-6349		
	Emergency	69	EG-5879		
	Emergency	175	EG-6235		

a. No initial notification is necessary for these emergency engines. [§ 63.6590(b)(3)]
b. The owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, for each affected facility, by October 20, 2013, including but not limited to:

   What This Subpart Covers
   1. § 63.6580 What is the purpose of subpart ZZZZ?
   2. § 63.6585 Am I subject to this subpart?
   3. § 63.6590 What parts of my plant does this subpart cover?
   4. § 63.6595 When do I have to comply with this subpart?

   Emission and Operating Limitations
   5. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary CI RICE located at an area source of HAP emissions?
   6. § 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

   General Compliance Requirements
   7. § 63.6605 What are my general requirements for complying with this subpart?

   Testing and Initial Compliance Requirements
   8. § 63.6615 When must I conduct subsequent performance tests?
   9. § 63.6620 What performance tests and other procedures must I use?
   10. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
   11. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

   Continuous Compliance Requirements
   12. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
   13. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

   Notifications, Reports, and Records
   14. § 63.6645 What notifications must I submit and when?
   15. § 63.6650 What reports must I submit and when?
   16. § 63.6655 What records must I keep?
   17. § 63.6660 In what form and how long must I keep my records?

   Other Requirements and Information
   18. § 63.6665 What parts of the General Provisions apply to me?
   19. § 63.6670 Who implements and enforces this subpart?
   20. § 63.6675 What definitions apply to this subpart?

EUG 37: Heaters Subject to only State Requirements

CD	EU	Point ID
1961	202	CDU H-2
1961	203	CDU H-3
1963	243N	LEU H-102 North
1963	243S	LEU H-102 South

a. OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.
b. The facility shall maintain records that show compliance with OAC 252:100-19-4.
c. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]
d. The heaters in EUG 37 may burn vent gas in excess of limits described in condition (c) and are exempt from monitoring. [CD]

EUG 38: Compression Ignition Internal Combustion Engines Subject to 40 CFR 63 Subpart ZZZZ

Engine Number	HP	USE	Fuel
EG 6192	603	Emergency	Diesel
EG 6217	603	Emergency	Diesel
EG 6218	603	Emergency	Diesel
EG 6312	603	Emergency	Diesel
EG 6289	603	Emergency	Diesel
EG 6290	603	Emergency	Diesel
EG 6472	170	Emergency	Diesel
EG 5886	363	Emergency	Diesel
EG 6031	290	Emergency	Diesel
EG 6522	330	Emergency	Diesel

a. No initial notification is necessary for these emergency engines. [§ 63.6590(b)(3)]
b. The owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, for each affected facility, by May 3, 2013, including but not limited to:

1. § 63.6580 What is the purpose of subpart ZZZZ?
2. § 63.6585 Am I subject to this subpart?
3. § 63.6590 What parts of my plant does this subpart cover?
4. § 63.6595 When do I have to comply with this subpart?
5. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary CI RICE located at an area source of HAP emissions?

6. § 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?
7. § 63.6605 What are my general requirements for complying with this subpart?
8. § 63.6615 When must I conduct subsequent performance tests?
9. § 63.6620 What performance tests and other procedures must I use?
10. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
11. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
12. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
13. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?
14. § 63.6645 What notifications must I submit and when?
15. § 63.6650 What reports must I submit and when?
16. § 63.6655 What records must I keep?
17. § 63.6660 In what form and how long must I keep my records?
18. § 63.6665 What parts of the General Provisions apply to me?
19. § 63.6670 Who implements and enforces this subpart?
20. § 63.6675 What definitions apply to this subpart?

EUG 39: New ROSE Heater

EU	Pollutant	Authorized Emissions	
		lb/hr	TPY
ROSE Heater 76 MMBTUH	SO_2	2.00	3.25
	NO_X	2.28	10.00
	VOC	0.67	2.95
	CO	5.00	21.0
	PM_{10} / $PM_{2.5}$	0.93	4.08

a. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. [OAC 252:100-19-4]

b. The above unit is subject to New Source Performance Standards (NSPS), Subpart Ja and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Ja]
   1. § 60.102a Emission limitations;
   2. § 60.103a Work practice standards as applicable;
   3. § 60.104a Performance tests as applicable;
   4. § 60.107a Monitoring of operations – (a)(2), (3), and (4); and
   5. § 60.108a Recordkeeping and reporting requirements.

c. The above unit shall only be fired with Subpart Ja compliant refinery fuel gas or pipeline-grade natural gas. The unit shall be equipped with a fuel gas meter. [40 CFR Part 60, Subpart Ja, OAC 252:100-8-6(a)(1)]

d. NOx emissions from each above heater shall not exceed 0.03 lb/MMBTU, expressed as NO_2. CO emissions shall not exceed 0.04 lb/MMBTU. PM emissions shall not exceed 0.0076 lb/MMBTU. CO_2e emissions shall not exceed 146 lb/MMBTU. [OAC 252:100-8-6]

e. Compliance with the CO_2e limitation shall be demonstrated by stack testing using Method 320 or an approved equivalent method capable of measuring emissions of CO_2, methane, and nitrous oxide (N_2O). [OAC 252:100-43]

EUG 40: New Hydrogen Plant Heater

EU	Pollutant	Authorized Emissions	
		lb/hr	TPY
H_2 Plant Heater 125 MMBTUH	NO_X	3.75	16.4
	CO	5.00	21.0
	VOC	0.67	2.95
	SO_2	3.30	5.34
	PM_{10} / $PM_{2.5}$	0.93	4.08

a. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. [OAC 252:100-19-4]

b. The above unit is subject to New Source Performance Standards (NSPS), Subpart Ja and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Ja]
   2. § 60.102a Emission limitations;
   3. § 60.103a Work practice standards as applicable;
   4. § 60.104a Performance tests as applicable;
   5. § 60.107a Monitoring of operations – (a)(2), (3), and (4); and
   6. § 60.108a Recordkeeping and reporting requirements.

c. The above unit shall only be fired with Subpart Ja compliant refinery fuel gas or pipeline-grade natural gas. The unit shall be equipped with a fuel gas meter. [40 CFR Part 60, Subpart Ja, OAC 252:100-8-6(a)(1)]

d. NOx emissions from each above heater shall not exceed 0.03 lb/MMBTU, expressed as NO_2. CO emissions shall not exceed 0.04 lb/MMBTU. CO_2e emissions shall not exceed 146 lb/MMBTU. PM emissions shall not exceed 0.0076 lb/MMBTU. [OAC 252:100-8-6]

e. Compliance with the CO_2e limitation shall be demonstrated by stack testing using Method 320 or an approved equivalent method capable of measuring emissions of CO_2, methane, and nitrous oxide (N_2O). [OAC 252:100-43]

f. The following measures shall be designed and constructed into the new Hydrogen Plant heater: [OAC 252:100-8-6(a)(1)]

- Maintenance and fouling control;
- Steam/feed preheating;
- Combustion air controls;
- Process integration (energy efficient design);
- Reformer with PSA hydrogen purification; and
- Latest proven burner designs.

EUG 41. Emergency Engine Subject to NSPS Subpart JJJJ

Point ID	Emission Unit	PM_{10} / $PM_{2.5}$		SO_2		NO_x		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
GE6500	Generac 58851	0.01	0.01	0.01	0.01	0.40	0.02	0.01	0.01	22.80	1.1

a. The above limits apply to non-emergency operations. Emergency operations are no subject to annual emissions limits but are subject to all requirements under NSPS Subpart JJJJ.

1. 60.4230: Am I subject to this subpart?
2. 60.4231: What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines?
3. 60.4232: How long must my engines meet the emissions standards if I am a manufacturer of stationary SI internal combustion engines?
4. 60.4233: What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?
5. 60.4234: How long must I meet the emissions standards if I am an owner or operator of a stationary SI internal combustion engine?
6. 60.4235: What fuel requirements must I meet if I am an owner or operator of a stationary SI internal combustion engine?
7. 60.4236: What is the deadline for importing or installing stationary SI ICE produced in the previous model year?
8. 60.4237: What are the monitoring requirements if I am an owner or operator of a stationary SI internal combustion engine?
9. 60.4238: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\leq$ 19 KW (25 HP).
10. 60.4239: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\geq$ 19 KW (25 HP) that use gasoline?
11. 60.4240: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\geq$ 19 KW (25 HP) that use LPG?
12. 60.4241: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program?
13. 60.4242: What other requirement must I meet if I am a manufacturer of stationary SI internal combustion engines?
14. 60.4243: What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?
15. 60.4244: What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?
16. 60.4245: What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?
17. 60.4246: What parts of the General Provisions apply to me?
18. 60.4247: What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines?
19. 60.4248: What definitions apply to this subpart?

INSIGNIFICANT ACTIVITIES

1. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTUH heat input (commercial natural gas).

    a. A list shall be maintained on-site.

2. Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for other emergency purposes, back-up purposes, and other purposes not part of normal operations service not exceeding 500 hours/year. The current engines will be insignificant sources until the compliance dates outlined in NESHAP Subpart ZZZZ.

    a. The facility shall maintain a record of the 12-month rolling total of the hours of operation for each piece of equipment included on the emergency power generation list.
    b. Any equipment added to the emergency power generation list will be disclosed to DEQ in writing within 30 working days after the equipment is put into operation.

3. Emissions from stationary internal combustion engines rated less than 50 hp output.

    a. A list shall be maintained on-site.

4. Cold degreasing operations utilize solvents that are denser than air, have a low vapor pressure and produce negligible emissions.

    a. For each designated piece of equipment the facility shall maintain on file a record, such as an MSDS, showing the name of the solvent used and a record of the solvent density.

5. Non-commercial water washing operations (less than 2,250 barrels/year) and drum crushing operations of empty barrels less than or equal to 55 gallons with less than three percent by volume of residual material.

    a. The facility shall maintain a record of the annual total number of barrels washed.
    b. The facility shall develop and implement a standard operating procedure to ensure the residual material in drums < 55 gallons is less than 3 percent by volume of residual material.

6. Hazardous waste and hazardous materials drum staging areas.

7. Hydrocarbon contaminated soil aeration pads utilized for soils excavated at the facility only.

8. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.

9. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas

10. Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in 252:100-8-3(e)(1).

11. Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period.

   a. Maintain a record of the monthly facility owned vehicle dispensed fuel amount.

12. Emissions from the operation of groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to limits for HAPS (§112(b) of CAAA90).

   a. A list of all equipment shall be maintained on-site.

13. Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature.

   a. The facility shall maintain a record on-site.

SPECIFIC CONDITION 3. The Permit Shield is identified in the Standard Conditions, Section VI. Permittee waives the extensive listing required by VI(B). [OAC 252:100-8-6(d)(2)]

SPECIFIC CONDITION 4. The drain rate of the LERU Caustic Scrubber system to the sewer shall not exceed 14 barrels per day and shall not exceed 75 gallons in any two-hour period. The facility complies with this requirement using equipment designed to limit draining.
[Consent Order 98-294]

SPECIFIC CONDITION 5. The owner/operator shall comply with all applicable requirements of the NESHAP: Industrial, Commercial, and Institutional Boilers and Process Heaters, Subpart DDDDD, no later than the date specified in the finalized subpart.

SPECIFIC CONDITION 6. No later than 30 days after each anniversary date of December 31, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, certification of compliance with the terms and conditions of this permit.
[OAC 252:100-8-6(c)(5)(A), (C) & (D)]

SPECIFIC CONDITION 7. No later than 3 years following issuance of Permit No. 98-114-C (M-19)(PSD), the facility shall submit to AQD a demonstration of compliance with the ambient impacts limitations of OAC 252:100-31 for H_2S. [OAC 252:100-31]

SPECIFIC CONDITION 8. The refinery fuel gas shall be treated and monitored to the sulfur specifications of NSPS Subpart Ja.

SPECIFIC CONDITION 9. New tanks will be added to the West Refinery, but the final designs are not yet ready. As an interim measure, a limit of 25.8 TPY VOC from the new tanks will be established. Roof landing losses should be included in tank VOC emissions as part of the 25.8 TPY total. The new tanks shall comply with NSPS Subpart Kb or MACT Subpart CC, as applicable. Applicability shall be determined on the operating permit application.

SPECIFIC CONDITION 10. The process heaters and boilers at the facility are subject to 40 CFR Part 63, Subpart DDDDD, and shall comply with applicable requirements as of the compliance date.

a. 63.7480 What is the purpose of this subpart?
b. 63.7485 Am I subject to this subpart?
c. 63.7490 What is the affected source of this subpart?
d. 63.7491 Are any boiler or process heaters not subject to this subpart?
e. 63.7495 When do I have to comply with this subpart?
f. 63.7499 What are the subcategories of boilers and process heaters?
g. 63.7500 What emission limits, work practice standards, and operating limits must I meet?
h. 63.7505 What are my general requirements for complying with this subpart?
i. 63.7506 Do any boilers or process heaters have limited requirements?
j. 63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?
k. 63.7510 What are my initial compliance requirements and by what date must I conduct them?
l. 63.7515 When must I conduct subsequent performance tests or fuel analyses?
m. 63.7520 What performance test and procedures must I use?
n. 63.7521 What fuel analyses and procedures must I use?
o. 63.7522 Can I use emission averaging to comply with this subpart?
p. 63.7525 What are my monitoring, installation, operation and maintenance requirements?
q. 63.7530 How do I demonstrate initial compliance with the emissions limits and work practice standards?
r. 63.7535 How do I monitor and collect data to demonstrate continuous compliance?
s. 64.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
t. 63.7541 How do I demonstrate continuous compliance under the emission averaging provisions?
u. 63.7545 What notifications must I submit and when?
v. 63.7550 What reports must I submit and when?
w. 63.7555 What records must I keep?
x. 63.7560 In what form and how long must I keep my records?
y. 63.7565 What parts of the General Provisions apply to me?
z. 63.7570 Who implements and enforces this subpart?

aa. 63.7575 What definitions apply to this subpart?

SPECIFIC CONDITION 11. As part of the Annual Compliance Certification, the permittee shall state the annual average H_2S concentrations in refinery fuel gas compared to the Projected Actual Emissions level of 25 ppm.

SPECIFIC CONDITION 12. The permittee shall apply for a modified operating permit within 180 days of start-up of any new unit authorized under this construction permit.

[OAC 252:100-8-6]

SPECIFIC CONDITION 13: As part of the operating permit application, the permittee shall submit maximum anticipated throughputs and resultant VOC emissions for the organic liquids storage tanks in EUG-19, EUG-20, EUG-21, EUG-22, EUG-23, EUG-24, EUG-25, EUG-27, and EUG-28. [OAC 252:100-8-6]

SPECIFIC CONDITION 14: Within 180 days following commencement of operations of any new or modified heater authorized by this permit, performance testing shall be conducted on the existing heaters taking $PM_{2.5}$ limits and a written report of results submitted to AQD. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality: [OAC 252:100-43]

Method 1:	Sample and Velocity Traverses for Stationary Sources
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
Method 4:	Moisture in Stack Gases.
Method 5:	Particulate Matter Emissions from Stationary Sources
Method 7E:	NOx Emissions from Stationary Sources
Method 10:	CO Emissions from Stationary Sources
Method 25A:	VOC Emissions from Stationary Sources
Method 202:	Condensable PM Emissions from Stationary Sources

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.
[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.
[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.

(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.

(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.

[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter.

[OAC 252:100-13]

(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]